COMBUSTION

DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

February 1960

Clothes are still being washed at the river's edge now in the shadow of the Bokaro, India power plant on the Damodar River

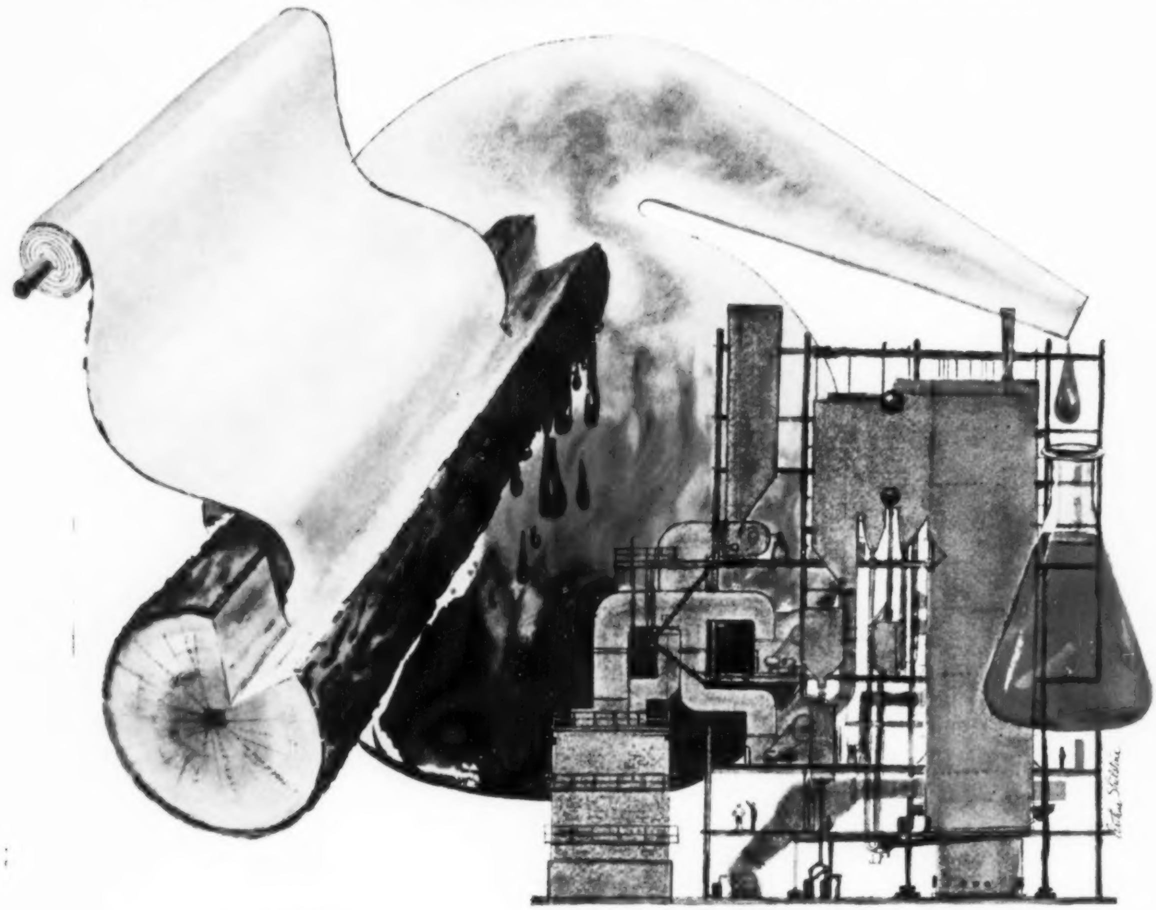
Steam Electric Power Costs

Feed Pump Flashing

Low Level Economizer

Boiler Efficiency Dilemma

"CREATIVE ENGINEERING" REAPS A CHEMICAL HARVEST . . . BUILDS PULP-AND-PAPER PROFITS



World's largest chemical recovery unit achieves unprecedented economies in the pulp and paper industry

Chemical recovery is basic to the multi-billion-dollar pulp-and-paper industry. Valuable chemicals are salvaged from "black liquor," a residue of pulp manufacture. And the modern recovery process also produces large quantities of by-product steam.

Just a few years ago, the industry believed that recovery units had reached maximum size, with capacities (black liquor dry solids) of about 1,000,000 pounds per day. C-E engineers, aware that larger installations would mean lower investment and operating costs per unit of capacity, developed half a dozen major innovations in quick succession—and broke through the size barrier.

Twenty-five units of more than 1,000,000-pounds capacity have since been purchased from C-E by leading producers. The largest of these—a 2,000,000-pound unit—has now been in service for more than a year. Despite their high initial costs, such units usually pay for themselves in about two years.

This concern with a specific industry's capital problems—and deep involvement with that industry's technology—is characteristic of the C-E approach.

"CREATIVE ENGINEERING" is the foundation on which Combustion's leadership rests. The products which bear the C-E mark of leadership include:

all types of steam generating, fuel burning and related equipment · nuclear power systems · paper mill equipment · pulverizers · flash drying systems · pressure vessels · soil pipe

COMBUSTION ENGINEERING

Combustion Engineering Building, 200 Madison Avenue, New York 16, N. Y.

C-193

COMBUSTION

DEVOTED TO THE ADVANCEMENT OF STEAM PLANT DESIGN AND OPERATION

Vol. 31 **No. 8**

February 1960

Feature Articles

Steam Electric Power Costs—1954 to 1958 .... *by H. E. Roberts* 30
Protecting Boiler Feed Pumps Against Flashing .... *by P. H. Hardie* 41
Design Performance of the Low Level Economizer ..... *by J. H. Porter and R. C. King* 45
The Boiler Efficiency Dilemma .... *by Geo. W. Switzer* 55
Good Lighting Practice for Modern Plants .... *by Peter Sherwood* 59
American Power Conference 62
Abstracts From the Technical Press—Abroad and Domestic 65

Editorials

On Standing Still 25

Departments

Advertising Index 74, 75

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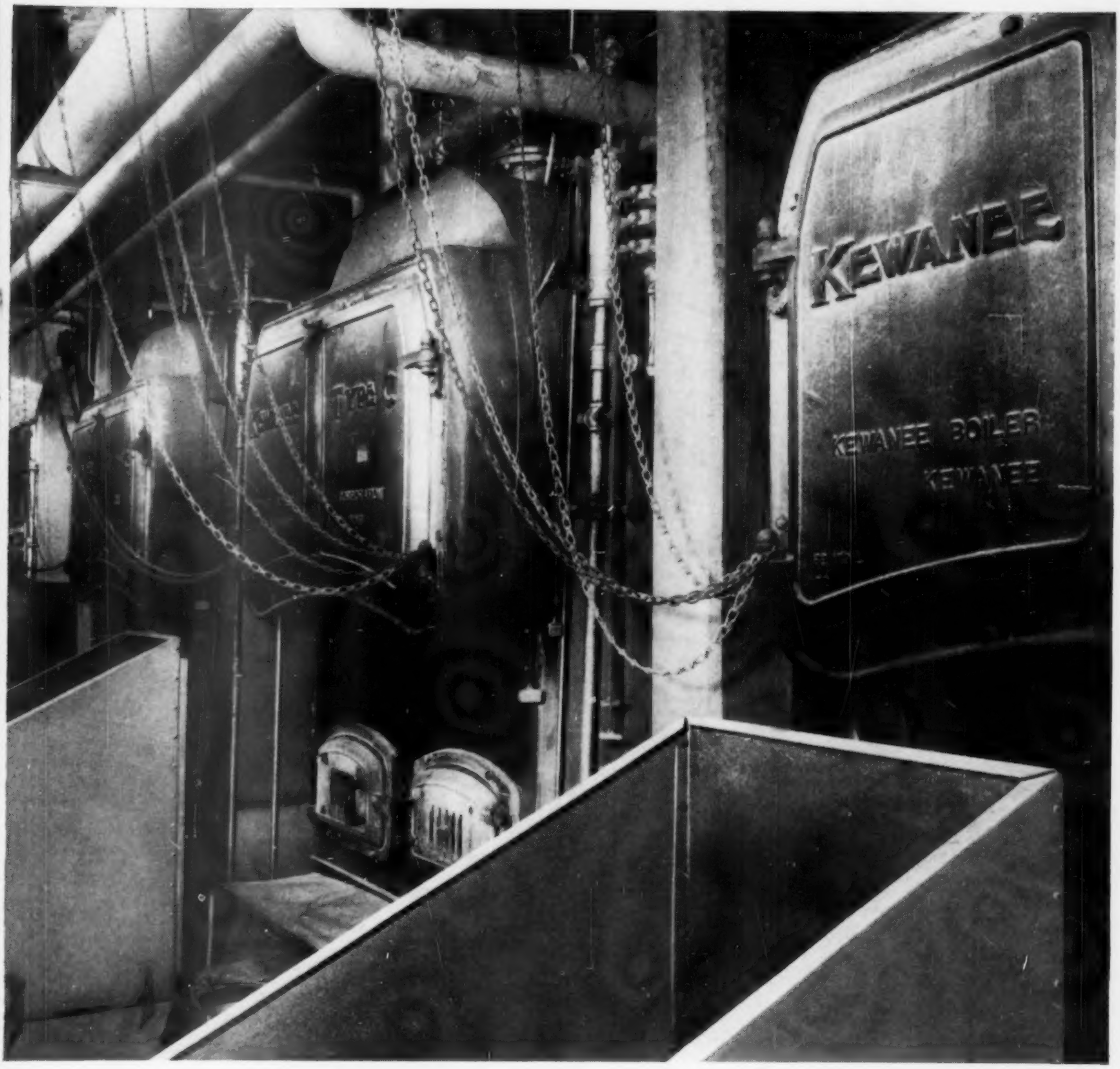

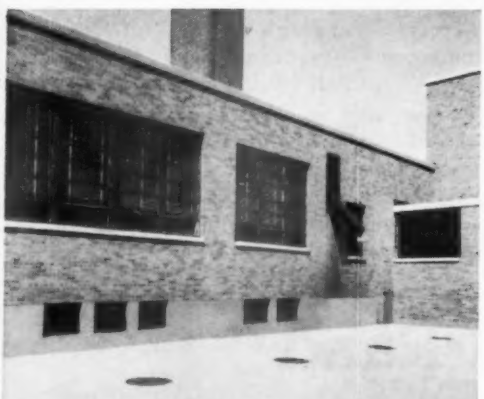

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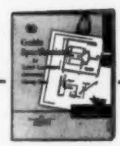
Guide Specifications, with complete equipment criteria and boiler room plans:



C-02

Bituminous Coal Institute
Southern Building, Washington 5, D. C.

Gentlemen: Please send me:

- ☐ GS-1 (low-pressure heating plant, screw-type underfeed stoker).
- ☐ GS-2 (high-pressure heating and/or process plant, ram-type underfeed stoker).
- ☐ GS-3 (automatic package boiler for heating and process plants).
- ☐ Case histories on larger plants.

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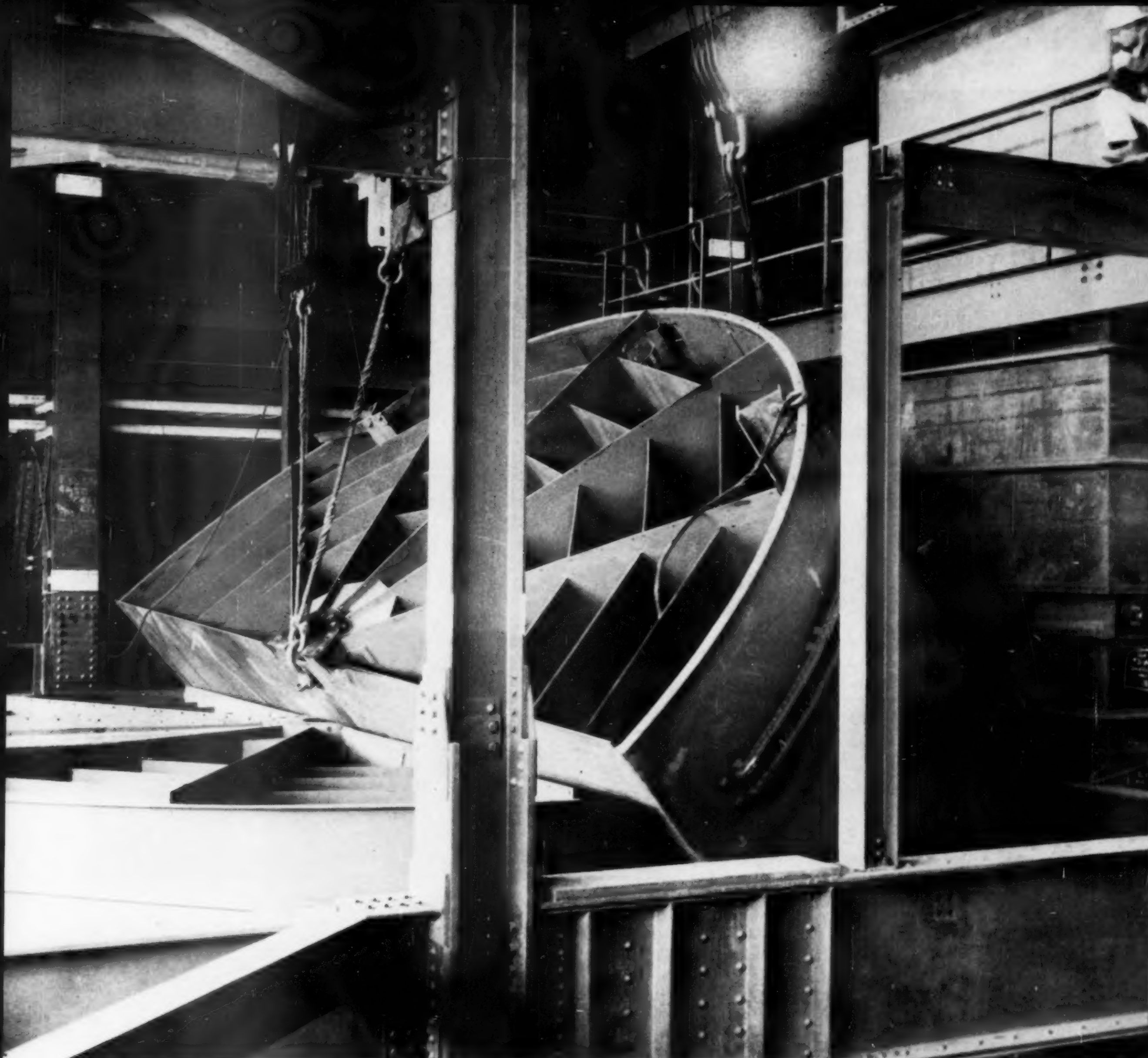


Half of Ljungstrom rotor is lowered into place at Philadelphia Electric Co.'s new Eddystone Station. When heating element baskets are fitted into the rotor chambers, this unit will provide 201,100 sq. feet of heat transfer surface and will weigh about 535,000 lbs. It will be one of four air preheaters serving a 325,000 KW unit. Two such boiler units are presently being installed.

SAFEGUARDING EDDYSTONE'S **NEW LJUNGSTROMS®** **—LIFETIME AIR PREHEATER SERVICE**

Dependability is standard equipment in Philadelphia Electric Co.'s new Ljungstroms. Each unit is protected by Lifetime Air Preheater Service. That means that *throughout the life of each unit*, Air Preheater engineers make regular calls to inspect the Ljungstroms and keep them in top operating condition.

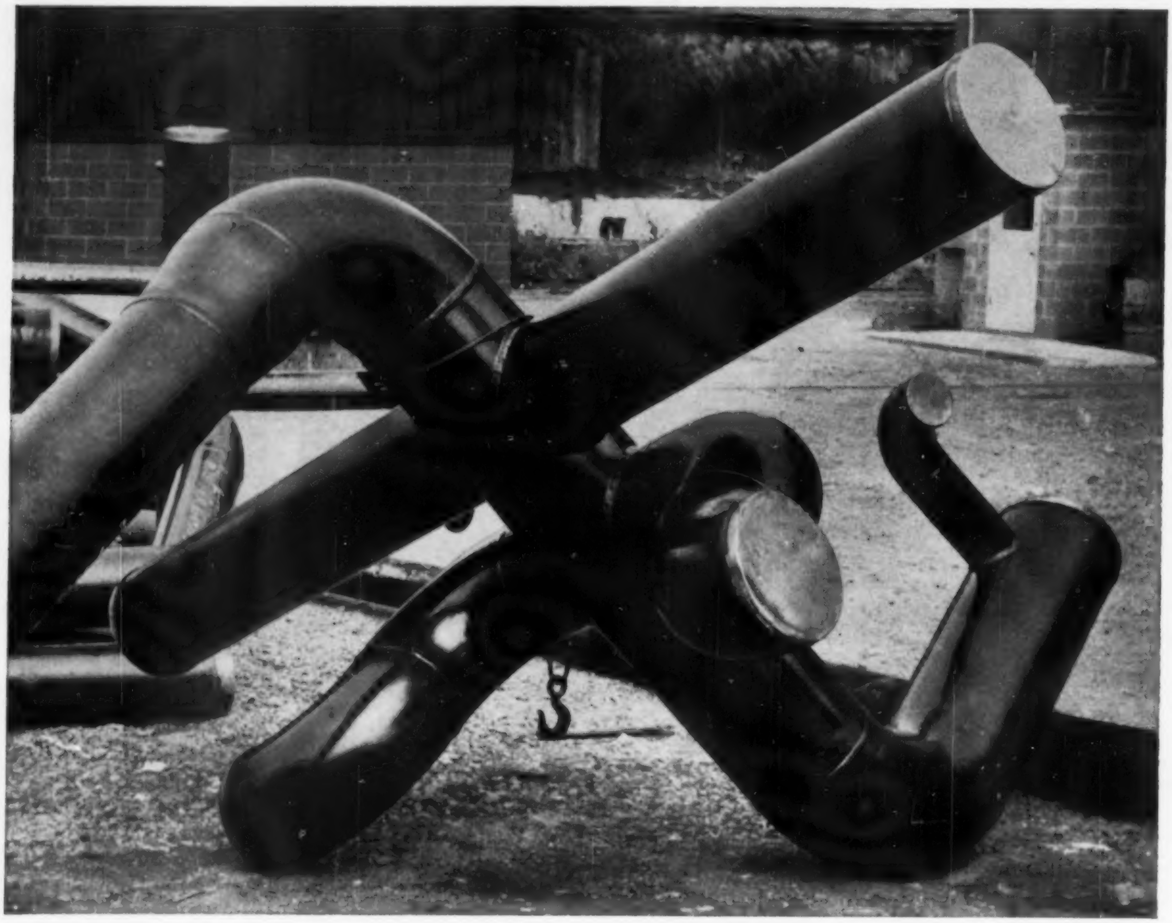
Air Preheater also shows lively, consistent interest in their *factory* service to customers. For example, when a midwest customer recently ordered emergency replacement elements, Air Preheater's traffic department investigated the cost, speed and control of all commercial shipping methods. In the circumstances, regular trucking would take too long, rail delivery was impractical, other methods prohibitively expensive.

So Air Preheater asked for authorization to ship the replacement elements aboard one of their own trucks. The result: the elements arrived a week in advance of the hoped-for date – and, thanks to Air Preheater's efforts, the customer made significant savings on transportation costs.

In addition to regular field service and fast, competent factory service, Air Preheater offers you over 35 years of experience in solving boiler and preheater problems. These reasons help explain why 19 of the 20 most efficient power stations in the U.S. are Ljungstrom-equipped.

THE AIR PREHEATER CORPORATION

60 East 42nd Street, New York 17, N. Y.



Shop fabrication of complex shapes such as this ⅜" wall service water header simplifies field erection.

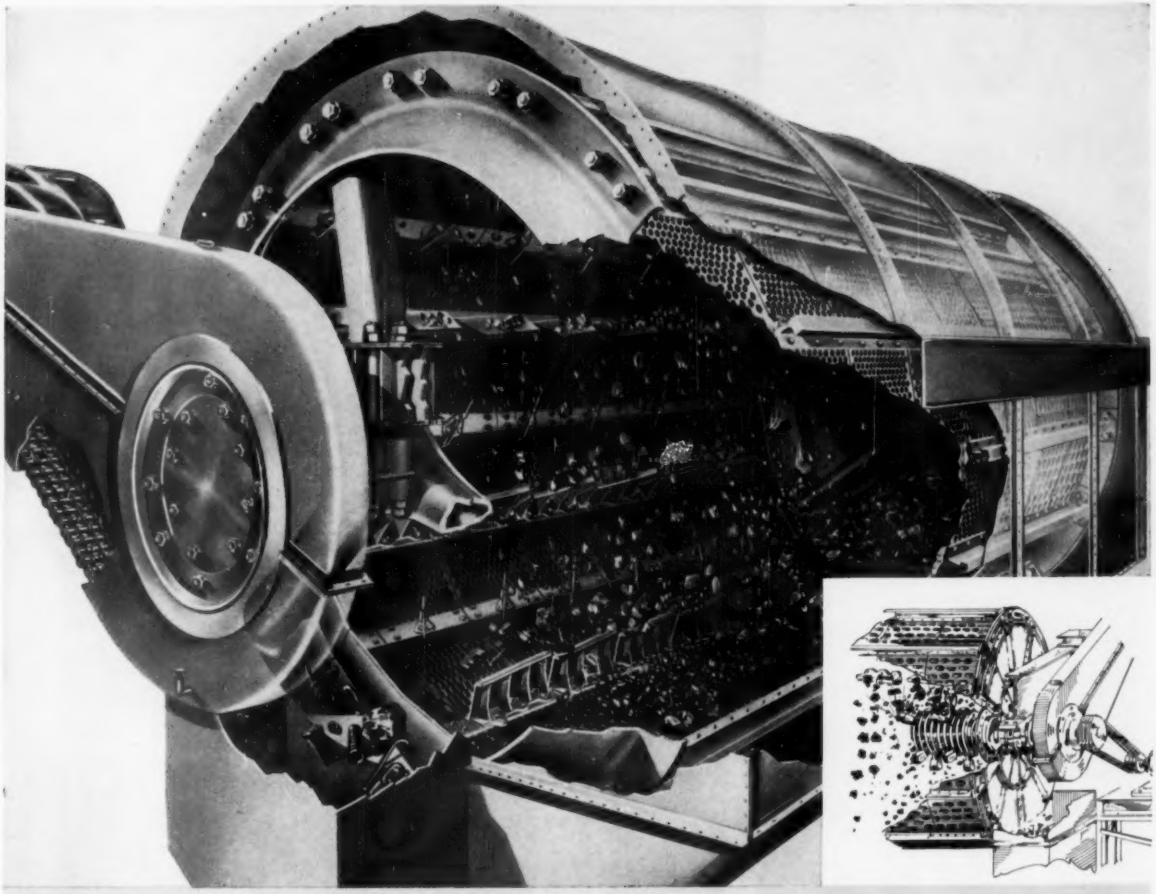


Illustration of modern Pennsylvania Bradford Breaker in operation. Note coal lifted and dropped for gravity-impact breakage passes through perforations when sized. Tramp iron and other refuse automatically discharged.

It cleans coal as it crushes AT NO EXTRA COST

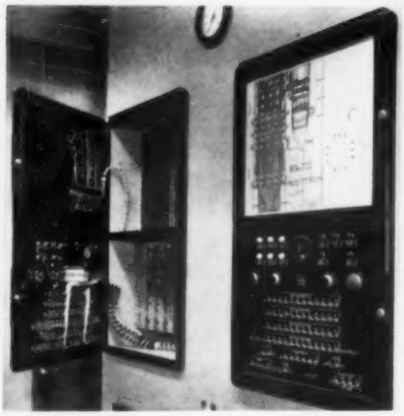
The Pennsylvania Bradford Breaker has no peer in the preparation of run-of-mine coals. This is borne out by the fact that Pennsylvania Bradfords condition over 38 million tons of coal annually in power plants all over the world. This has been going on for many, many years and it's your assurance of dependability. For the preparation of extra hard coals the Pennsylvania Bradford Hammermill is usually preferred. This crusher is a Bradford Breaker with a swing hammer rotor placed at the discharge end that reduces all oversize so it can pass thru the cylinder perforations, thus eliminating any waste of oversize that otherwise might pass out the discharge end.

For complete information on these Breakers, ask for Bulletin 3009. Pennsylvania Crusher Division, Bath Iron Works Corporation, West Chester, Pennsylvania.

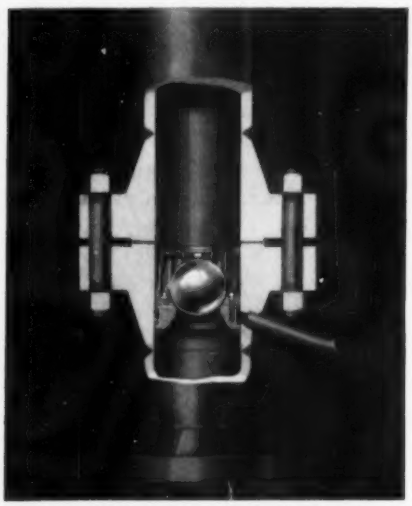
Pennsylvania CRUSHERS

Nuclear

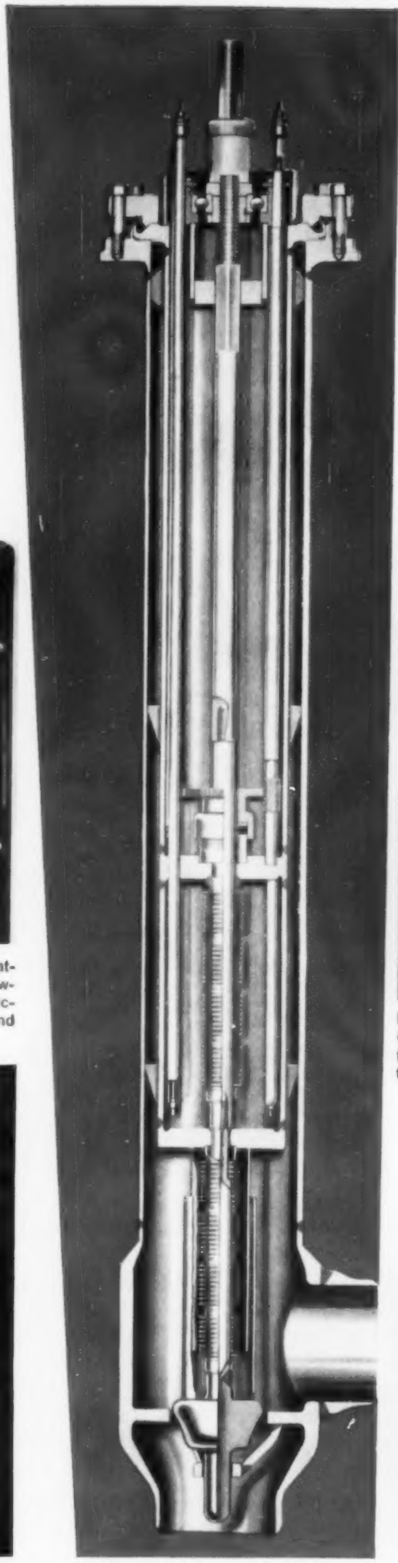
with



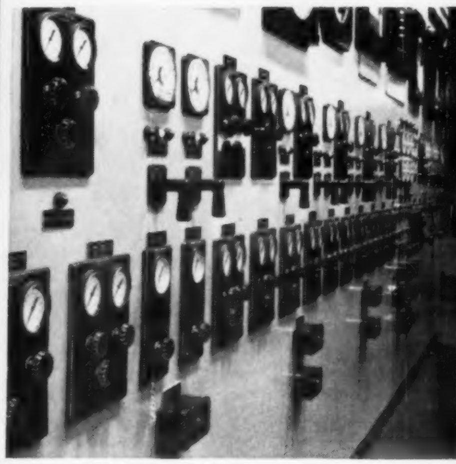
Automatic soot blowing permits varying the operating sequence of air- or electrically-driven soot blowers. Vulcan Selective-Sequence and Automatic-Sequential systems assure positive cleaning, and save blowing medium. Write for Bulletin 1029.



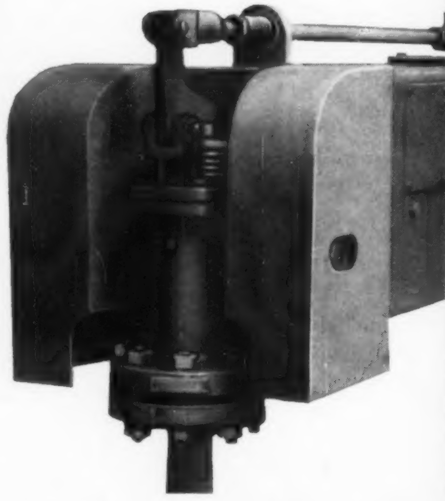
Variable-Orifice Desuperheater* holds reduced steam temperature constant close to its outlet. Write for Bulletin 1037. Carburetor and Steam-Assist types are also available for steam service conditions through 2500 psig and 1100 F. **Patent applied for.*



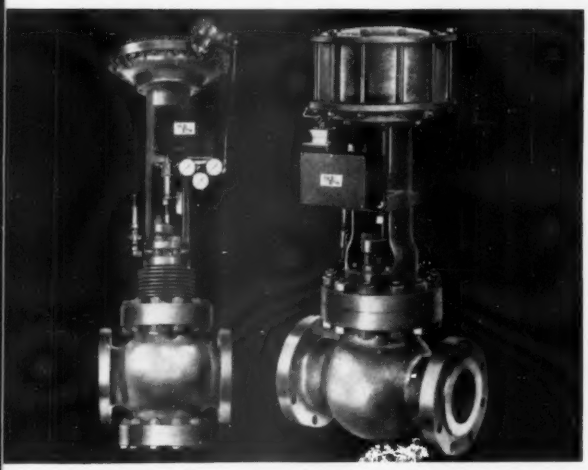
Nuclear valves meet rigid requirements for resistance to corrosion, fail-safe operation, and remote maintenance. Components are thoroughly cleaned and assembled in a sterile atmosphere.



Boiler control provides high-speed response. Combustion control may be from steam flow—air flow, or fuel-air ratio. Feedwater control from one, two, or three influences. Write for Bulletin 1038.



and fossil-fuel plants power up Copes-Vulcan equipment



Control valves for flow, pressure, and temperature of fluids or gases are job-tailored for accuracy and dependability. Diaphragm- or piston-operated types are available in pressure standards from 125 through 2500 psig. Both offer excellent rangeability. Write for Bulletin 1027.

In conventional, super-critical, and nuclear power stations on land . . . aboard conventional and nuclear-powered ships at sea, Copes-Vulcan precision-built control systems increase efficiency.

Meeting exact design requirements, Copes-Vulcan builds control systems for combustion, feedwater, superheat and reheat steam temperatures, pressure reducing, desuperheating, and soot blowing.

Copes-Vulcan is also experienced in the design and manufacture of such special products as nuclear valves.

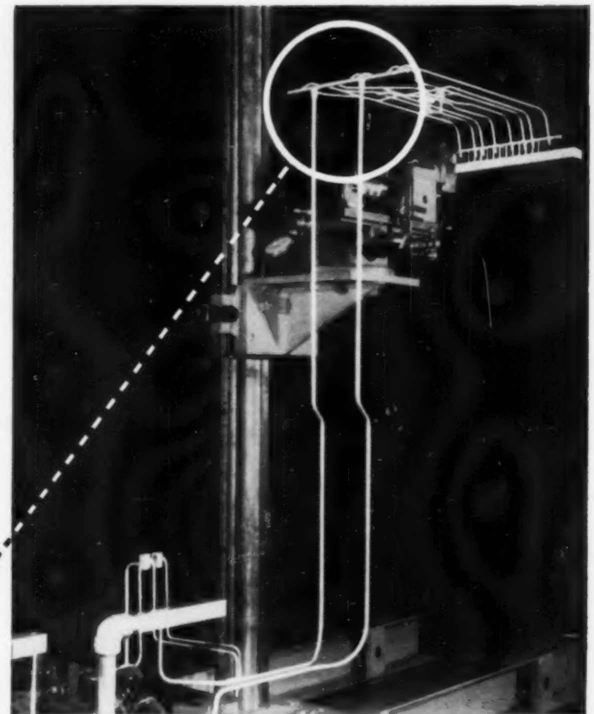
All systems are custom-engineered, and backed by over 50 years of experience. Copes-Vulcan Division, Erie 4, Pa.

Extra-long soot blower, Vulcan T-30, is built for travels up to 40 feet. Dual-motor drive gives multi-helix blowing pattern for thorough cleaning of all surfaces. All working parts encased for protection. Write for Bulletin 1030.

Copes-Vulcan Division

BLAW-KNOX

6 Ton Hot Reheat Header



Model test set-up of hot reheat line as reproduced above is approximately 1/10th actual size of the model. Circled area shows position of chrome-moly header in the line.

Size of this hot reheat header can be seen by comparison with men in the picture. It is 21″ O.D., fabricated of 2¼% chrome, 1% molybdenum steel.

PRETESTED and PREFABRICATED by *Pittsburgh Piping*

PART OF A COMPLETE HIGH-PRESSURE, HIGH-TEMPERATURE PIPING SYSTEM

The model shown above exactly duplicates—from an engineering standpoint—a hot reheat line which is part of a high-pressure, high-temperature piping system fabricated by Pittsburgh Piping.

The inset shows the position and relative size of the header in the line, and the main illustration is an actual photograph of this header as fabricated in our shops. The complete system, which includes chrome-moly and stainless steel piping fabrication, is one of scores of installations which we have model-tested, fabricated, and erected.

Use this experience on your next piping job . . . electric generating station, nuclear power installation, chemical processing plant, refinery, mill, or factory. We are specialists with complete facilities, and we assume responsibility for every phase of the work—from blueprint through erection.

Promoting Progress ***IN POWER AND PROCESS PIPING***

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PP-36

QUALITY IS ALWAYS THERE IN VALLEY CAMP QUALITY COALS

From the time raw coal leaves the mine and is mechanically conveyed through all the processes of crushing, washing, sizing, and thermal drying, right up to shipment... quality, plus quality control, is a vital part of our coal preparation.

Ask our combustion engineering service how this quality, plus quality control pays off in lowered steam costs for you.

THE VALLEY CAMP COAL COMPANY

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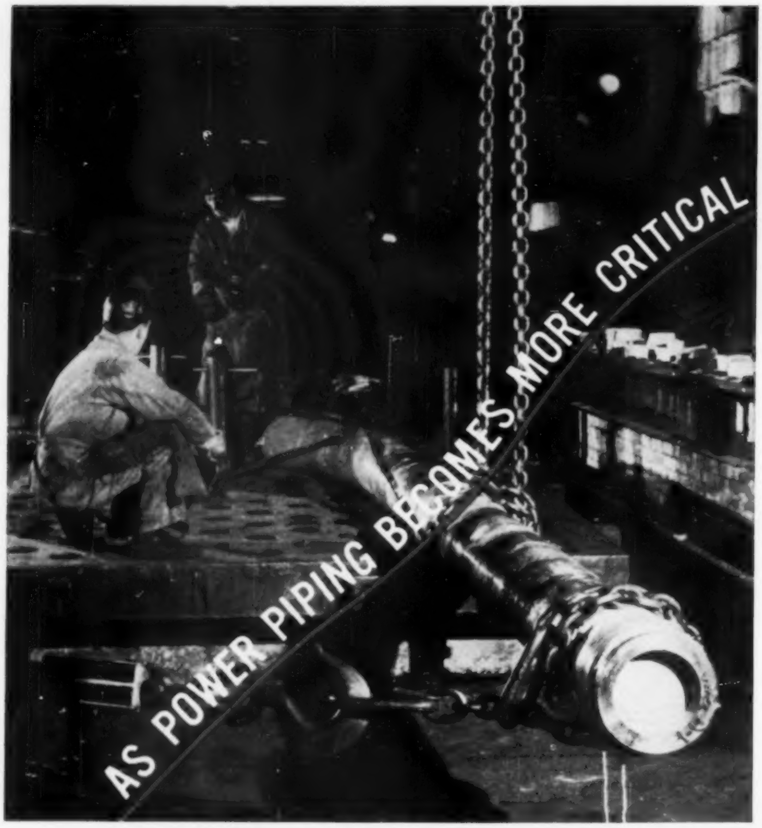

KELLOGG'S PIPE BENDING TECHNIQUES KEEP PACE

A length of stainless steel piping is bent to close tolerances at Kellogg's Jersey City shops. Dam in pipe end retains inert gas introduced to prevent oxidation.

Bending stainless, chrome-moly, and carbon steel power piping to meet exacting specifications of length and wall thickness, as well as contour, is a Kellogg skill reflected in a higher quality and lower cost product.

Among the advanced fabricating techniques pioneered by Kellogg at its Jersey City shops is the use of inert gas to purge pipe interiors of oxygen during the heating and bending cycle. This technique assures freedom from internal scaling and provides a clean interior surface.

By its ability to predetermine bending effects such as pipe wall thinning, cross section variations and pipe stretch, Kellogg maintains specification requirements and top quality while minimizing bending costs.

Kellogg welcomes inquiries on its complete design, fabrication, and erection service to the power piping industry from consulting engineers, engineers of power generating companies, and manufacturers of boilers, turbines, and allied equipment.

Operator checks pressure of inert gas being forced through piping during heating to prevent internal scaling. Gas is also retained in the piping during bending.

THE M. W. KELLOGG COMPANY, 711 THIRD AVENUE, NEW YORK 17, N. Y.
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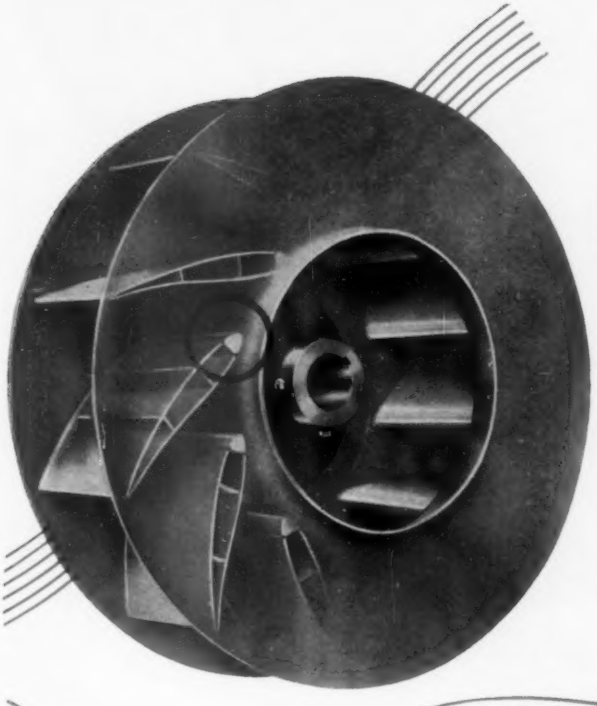
POWER PIPING—THE VITAL LINK



COSTS HELD DOWN WHEN INLAND® INCLUDED

Green *Airfoil* Fans

IN FURNACE REBUILDING

At their #2 plant in East Chicago, Indiana, Inland Steel completely rebuilt and enlarged their furnaces to increase production. These rebuilt furnaces called for greater induced draft capacity in the waste heat boilers. The old fan installation of 7 Green radial blade fans had been installed 24 years ago.

Inland Steel replaced these 7 Green fans with 7 Green AIRFOIL induced draft fans. No changes were made in the original motors or electrical system. The 7 Green AIRFOIL fans took care of the increased draft requirements without overload on the original 125 hp motors.

In short, the new Green AIRFOIL fans made it possible for Inland Steel to increase the size and capacity of their furnaces without the expense of new motors and electrical installations in addition.

The Green AIRFOIL design provides smooth airflow with a minimum of turbulence. For longer life, the AIRFOIL fan blades have specially designed cast steel nose pieces to reduce wear. (See circled nose piece in illustration.)

If you have a tough job for heavy duty fans, it makes sense to talk over your problem with Green.

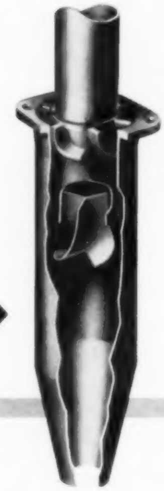
Green

THE GREEN FUEL ECONOMIZER CO., INC., BEACON 3, NEW YORK

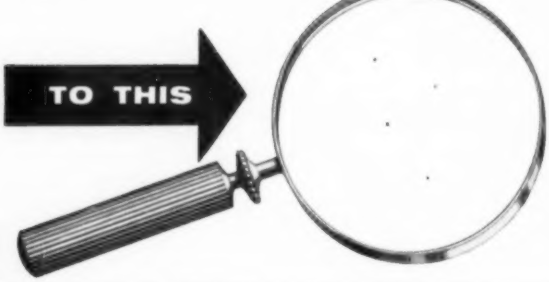

Specialist needed!

This is a
Dust
Particle

This is a
Cyclo-trell
Dust
Collector →



The Cyclo-trell Dust Collector Cleans Gas with these Dust Particles . . .



Result: Efficiencies Exceeding 98%

This is a fact. If you have a process or cleaning problem in steel mills, refineries, paper, cement or chemical plants, call on Research-Cottrell. • We will be glad to consult with you on your specific dust collection problems, and place at your disposal the largest research and engineering facilities.

For further information, write for Bulletin 300 which describes several applications in detail.

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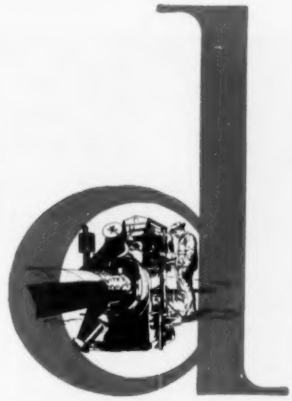
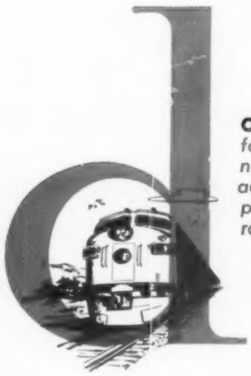
RESEARCH COTTRELL INC
TRADE MARK

dearborn *research leads the way in all fields of corrosion control*

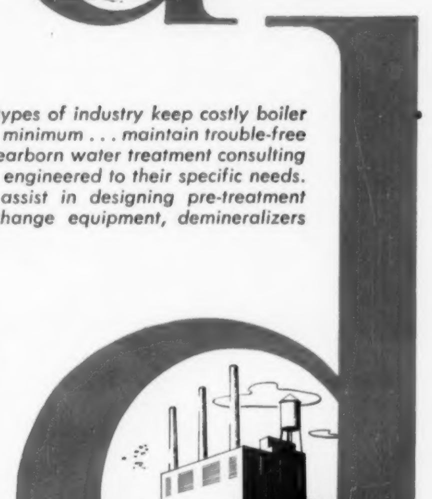


PIPE LINE *corrosion specialists call for both mechanical and chemical protection and get it with Dearborn's NO-OX-ID* coatings and wrappers . . . underground and underwater protection that lasts for decades.*



ON RAILROADS, *Dearborn's water treatment formulas and sludge solvents keep diesels running longer and cleaner. NO-OX-ID* coatings add years of life to trestles and bridges. Exclusive pressure washing systems and cleaners keep rolling stock bright . . . reduce maintenance costs.*

SHIP OWNERS *depend on Dearborn's NO-OX-ID* coatings for long term protection against the continuous corrosive attack of inland and salt waters.*



POWER ENGINEERS *in all types of industry keep costly boiler down-time and repairs at a minimum . . . maintain trouble-free cooling systems . . . with Dearborn water treatment consulting service and test equipment engineered to their specific needs. Dearborn engineers also assist in designing pre-treatment systems including ion-exchange equipment, demineralizers and softeners.*

pioneer in the science of corrosion control

If your responsibilities include any phase of water treatment or corrosion control, you should be receiving Dearborn's valuable research and technical bulletins. A request on your Company letterhead will bring them regularly.

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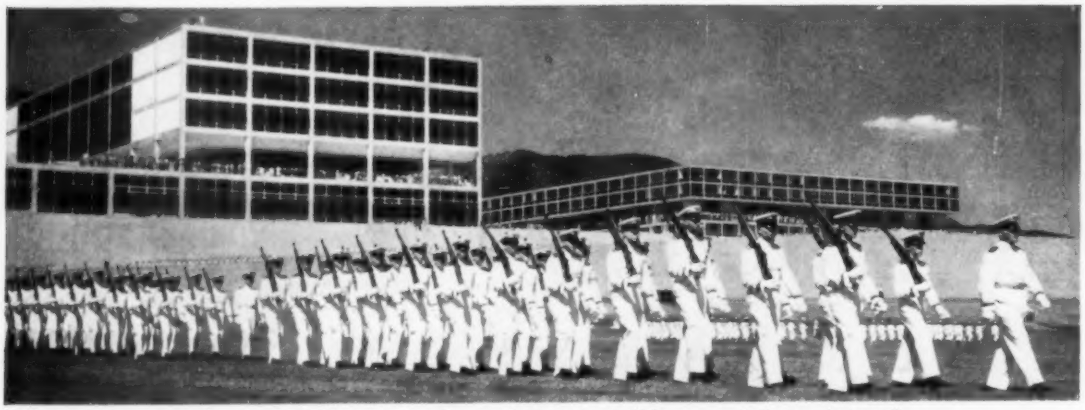
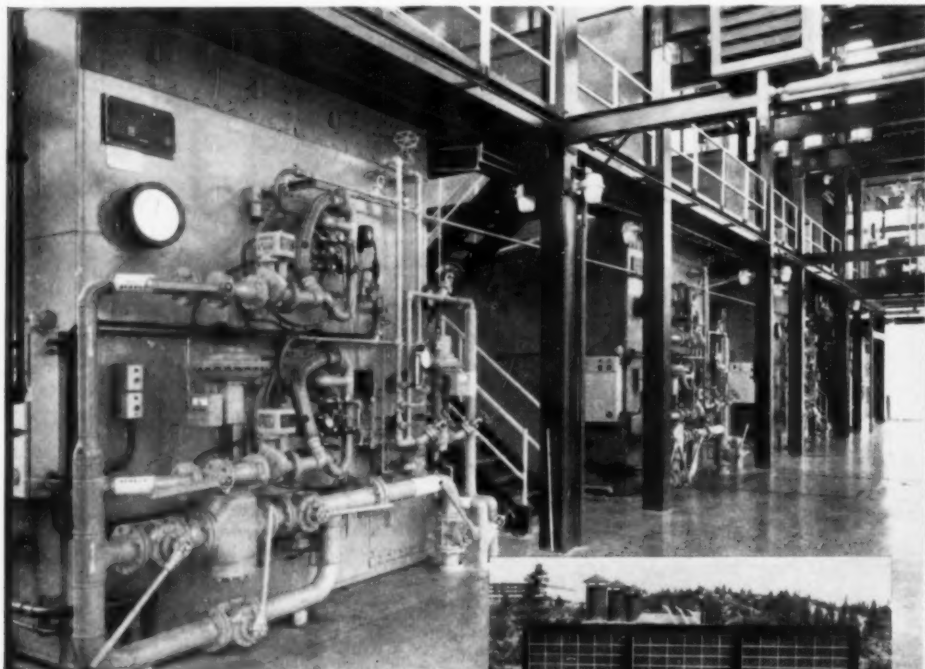


Without breaking step, students march down ramp leading from academic and cadet living area onto the parade ground.

HIGH TEMPERATURE WATER HEATS



Compact and efficient, these three C-E LaMont Controlled Circulation Hot Water Boilers serve in the Academy's Academic Area plant. Each has a rated output of 100 million BTUs per hour.

The Academic Area plant, at right, houses the three C-E LaMont Controlled Circulation Hot Water Boilers shown above. The Service Area plant has two smaller C-E LaMont Boilers, each with a rated output of 30 million BTUs per hour.

Catalog HCC-2, describing the C-E Hot Water Boiler, available on request.

ALL TYPES OF STEAM GENERATING, FUEL BURNING AND RELATED EQUIPMENT; NUCLEAR REACTORS;

Nestled picturesquely in the Rampart Range of the Rockies, seven miles north of Colorado Springs, the new U. S. Air Force Academy is a fitting symbol of the prowess and prestige earned by this branch of our military.

Situated on a sloping site, the Academy grounds are graded, split-level fashion, into a number of broad terraces. Elevations range between 6,400 and 7,000 feet above sea level. The school is divided into two general areas – one for service buildings and one encompassing academic, physical education, dormitory and hospital facilities.

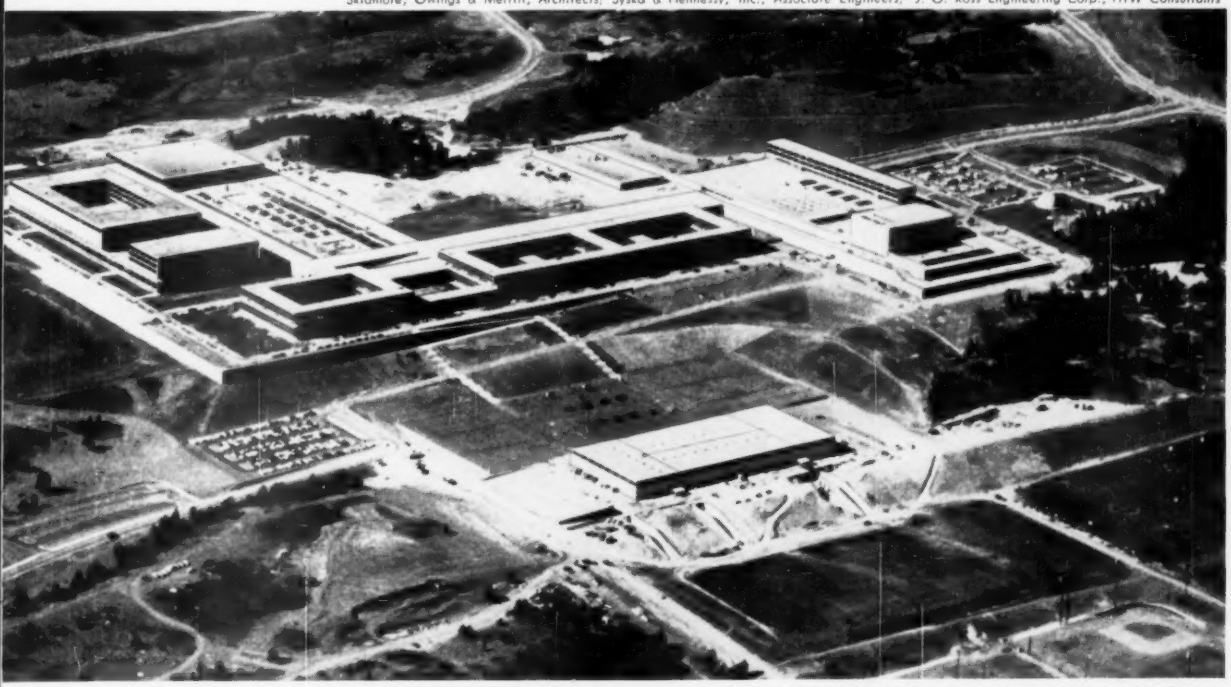
Selecting a heating system to service these widely-spaced buildings and facilities over the rolling and varying terrain required a type that permitted easy and economical pipe line distribution over individual closed circuits exceeding six miles in length—circuits which totally encompass nearly 15 miles.

Because of the irregular terrain and the large area, a steam system would have required a substantial number of steam traps and close attention to piping gradients. High temperature water, on the other hand, offered the advantages of smaller-sized piping with no pressure valves, and a smaller, more compact boiler plant than would have been required for steam ...with 10 to 20 per cent reductions in operating costs.

There are five C-E LaMont Controlled Circulation Hot Water Boilers serving the Air Force Academy. They are located in two separate boiler plants—3 in one and 2 in the other—and have been performing reliably, efficiently and with minimum operating attention since they were first placed in service in late 1957.

THE AIR FORCE ACADEMY

Skidmore, Owings & Merrill, *Architects;* Syska & Hennessy, Inc., *Associate Engineers;* J. O. Ross Engineering Corp., *HTW Consultants*



Nestled against the Rampart Range of the Rockies, the Academy presents an impressive sight from the air. Buildings, from left to right, are: Fairchild Hall, the Academic-Library Building, with Aerodynamics-Thermodynamics Lab and Mitchell Hall (Cadet Dining Hall) behind it; Vandenberg Hall, the Cadet Dormitory; Harmon Hall, the Administration Building; Arnold Hall, the Cadet Social Center; and Planetarium (dome at right). The parade ground stretches at left from sloping ramp. The Physical Education Building and athletic fields are at lower right.

COMBUSTION ENGINEERING

Combustion Engineering Building, 200 Madison Avenue, New York 16, N. Y.

C-246

Canada: Combustion Engineering-Superheater Ltd.

PAPER MILL EQUIPMENT; PULVERIZERS; FLASH DRYING SYSTEMS; PRESSURE VESSELS; SOIL PIPE

COMBUSTION

Editorial

On Standing Still

Establishing and maintaining an effective, imaginative organization within any concern is vital to that concern's growth. Further, the stronger the individual concerns making up a given industry, the better that industry serves the general economy. Fundamental, of course. Yet we found ourselves suffering some doubts about the power industry's awareness of these fundamentals at this comment in a formal paper before the AIEE winter general meeting. "I've heard some badly informed opinions to the effect that the power industry has solved all its technical problems and it's just a matter of doing the same thing over and over again to keep up with our growth." We've heard the same opinions and on college campuses!

Charles E. Eble, president of the Consolidated Edison Co. of New York, was the author of this comment and he used it in exhorting the power industry to sell itself better to young engineers. Certainly the presence of such opinions is dangerous to good recruiting. The so-called "glamour" industries of electronics, rocketry and the like exert a strong enough appeal to the young engineer without the handicap of misconceptions of the power industry and its challenges.

In this issue on page 26 appears a sharply drawn article on the power industry today and its growth within the five year span 1953–1958. The author states "... this net increase of 43,600 Mw thermal capacity during the five year period is approximately equal to the total thermal capacity installed in the 28 year period, 1925 through 1953." Obviously here is no industry standing still. Moreover, at the recent FOF meeting we heard many discussions of the role of specially designed peaking units, and the advent of the low level economizer. But all these remarks come from seasoned, established engineers. The young embryo engineer and, alas all too often, his instructor are not at all aware of the intensive studies and probes the power industry daily conducts to better its operations.

Here, in attracting capable people, is an area, as Mr. Eble points out, where the industry needs to conduct its next intensive study. The cooperative plan employed by some colleges is an attempt to give understanding to the undergraduate engineer. The suggestion advanced in December 1959 COMBUSTION by Commander R. L. Brooks on improving understanding by guiding the selection of thesis subjects was still another method of bridging the gap between campus and industry. But there must be more ways that will reach more prospects. Let us urge that the industry pool its resources and its imagination in developing ways and means of attracting a proper proportion of the better equipped engineering graduates into its activities.

Five years is a very short period in this era of guided missiles, space exploration, and the ever-continuing inflationary spiral. Just what has happened in the field of steam-electric power production by the electric utility industry during these five years? A paper by Mr. Roberts, published in the June 1955 issue of COMBUSTION, reviewed such production and the associated costs for the period 1940 through 1953. The happenings and the accomplishments during the interim are the subjects of this valuable paper.

Steam-Electric Power Costs*—1954 to 1958

By H. E. ROBERTS†

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THE electric power industry's increase in total generating capacity during the five years, 1953 through 1958, is quite remarkable. The situation for the 48 states is summarized in brief form. The new states of Alaska and Hawaii are not included.

MEGAWATTS—INSTALLED CAPACITY

Class Utility	Thermal	Hydroelectric	Total
	December 31, 1958		
Privately-owned	95,545	12,391	107,936
Publicly-owned	17,505	16,972	34,477
Total	113,050	29,363	142,413
	December 31, 1953		
Privately-owned	60,674	10,527	71,201
Publicly-owned	8,783	11,518	20,301
Total	69,457	22,045	91,502
	Net Increase		
Privately-owned	34,871	1,864	36,735
Publicly-owned	8,722	5,454	14,176
Total	43,593	7,318	50,911

In a brief span of five years there was, after taking into account the retirement of the old, worn-out and obsolete generating equipment, a net increase of approximately 55 per cent in the total generating capacity and of almost 65 per cent in the thermal capacity. Conventional steam power constitutes 98 per cent of the thermal capacity. Only 2 per cent is in the internal combustion and gas turbine plants. This capacity as well as the annual output are of less relative importance each succeeding year. An interesting observation is that this net increase of 43,600 Mw thermal capacity during the five year period is approximately equal to the total thermal capacity installed in the 28 year period, 1925 through 1953.

The total output of the thermal capacity was 337.4 billion kwhr in 1953 and 504.7 billion kwhr in 1958. Hydroelectric production was 105.2 billion kwhr in 1953 and 140 billion kwhr in 1958. The thermal production increased 50 per cent while hydro was increasing 33 per cent.

The Immediate Future

Looking into the near future, as of midyear 1959, we find that the electric utility industry has scheduled and under construction approximately 40,000 Mw of steam-electric capacity in some 280 units for service in the five year period, 1959 through 1963. No doubt, a few small units, which do not require as much time to build and install as do the larger units, will be added to this total for 1962 and 1963 service. Perhaps, a few of the large units planned for 1964 will be rescheduled for late 1963. However, this should not disturb the above picture to any great extent.

Simple arithmetic gives an average size of 143 Mw for these 280 units. The total includes 1-600, 5-500, 2-450 and 20-300/350 Mw units for service in widely scattered parts of the country. The 600 Mw and three of the 500 Mw units will be on the TVA system, and one of the 300 Mw units will be in Arkansas. These 28 units add up to roughly 25 per cent of the total schedule. More of these very large units will be scheduled for 1964 and 1965.

Returning to the previous five years, the question is then: What did it cost to install the 43,600 Mws of steam-electric capacity and what effect has its addition to the national power supply had upon the total production costs of steam power during the period under review? Just what have the planners, the design engineers, the equipment manufacturers, the construction and operating forces accomplished in face of the continuing inflationary forces? The well-known *Engineering-News Record* Construction Cost Index was up over 25 per cent for the period 1953 to 1958 and the U. S. Bureau of Labor Statistics Wage Index for electric utility workers increased 21 per cent in the same period. Other cost indices show comparable increases. The record speaks

* The Federal Power Commission, as a matter of policy disclaims responsibility for any private publication of any of its employees. The views expressed herein are those of the author and do not necessarily reflect the views of the commission.

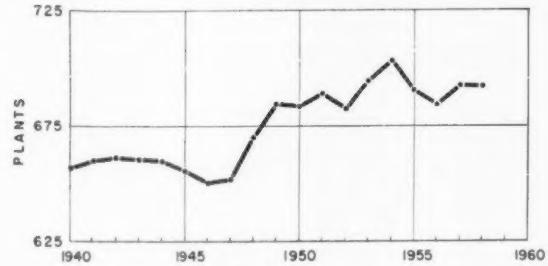


Fig. la—The number of steam-electric plants in Class A and Class B privately-owned utilities shows above

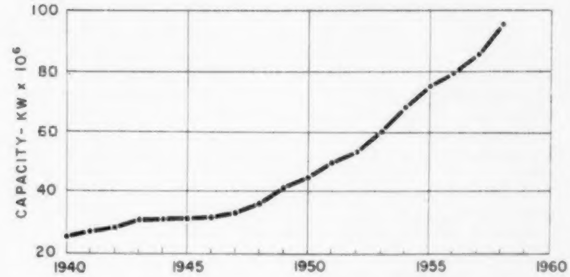


Fig. 1b—Total capacity in millions of kw for the plants in Fig. la has risen along this line

for itself. Concisely stated, the inflationary forces did not gain very much ground in the electric utility power production field during the five years. Some of the interesting details of the story of what has happened, and is continuing to happen, is illustrated in the accompanying charts and tables.

Class A and B Privately-Owned Utilities

The cost analyses from which these charts and tables were prepared relate only to the class A and B privately-owned electric utilities for which complete and generally comparable cost data are available. This group constitutes over 98 per cent of the privately-owned segment and about 77 per cent of the total industry in terms of total steam generating capacity. There are excellent cost data available pertaining to the construction costs and annual production expenses for many of the publicly-owned systems such as TVA and most of the larger municipal systems, rural cooperatives and power districts. However, due to the inherent differences in methods of financing with the resultant differences in the cost of money and the wide variances in tax liabilities, especially the income and ad valorem taxes, the annual fixed charges on the plant investment in the privately-owned systems are not comparable with the much lower corresponding fixed charges for the publicly-owned systems. When the annual fixed charges vary so materially direct comparisons of total costs are not meaningful.

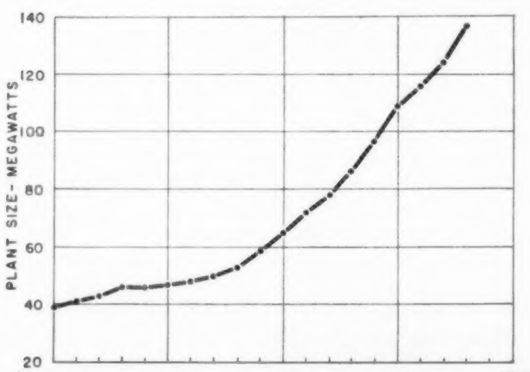
The Components of Total Production Costs

The total annual cost of steam-electric power production consists of two principal components—(1) The production expenses—operation excluding fuel, maintenance and fuel considered as a separate item. (2) Annual fixed charges on the plant investment, i.e., return on investment (interest costs), depreciation, taxes and insurance. The latter is a minor item which is often included in operating costs. Allocated "Administrative and General Expenses" may be included with either of these components or be included in the total cost as a separate item. It is another minor cost item so far as the portion allocated to power production is concerned. A reasonable allowance is about 20 per cent of the operation and maintenance expenses exclusive of fuel costs. It may range from 15 to 30 per cent.

The uniform accounting methods used by the industry produce excellent cost data for the "Production Expenses" category. Likewise they result in very good capital or investment costs, usually quite comprehensive for the individual plants. Hence, investment costs and production expenses present no particuliar problems in cost analyses.

Annual fixed charges on the steam-electric plant investment do present problems because of the several cost allocations that must be made so as to arrive at such costs. Reasonable and consistent assumptions must be made all along the line if the total of such fixed costs are to be assigned equitably to the "Production," Transmission," and "Distribution" functions of an electric utility system. It should be readily understandable why such allocated costs are often referred to as "estimated" rather than actual costs.

The Uniform System of Accounts for electric utilities is in common usage throughout the United States. As far as the annual income statement is concerned, it



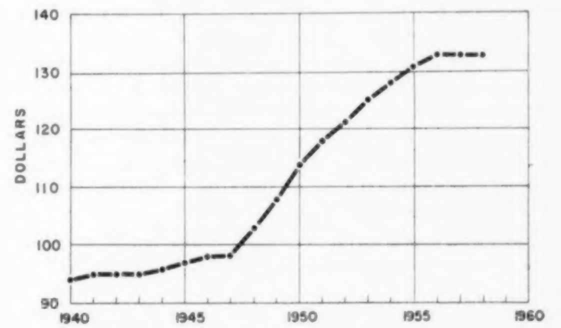


Fig. 1c—The weighted average historical cost per installed kw in dollars is portrayed by the chart above

Fig. 1d—The curve to the left pictures the increase in plant size in installed megawatts

TABLE I—TOTAL COST OF PRODUCING STEAM-ELECTRIC POWER, CLASS A & B PRIVATELY-OWNED ELECTRIC UTILITIES

	Mills Per Kilowatt Hour						
	1940	1953	1954	1955	1956	1957	1958
Production Expenses							
Operation	0.67	0.64	0.66	0.59	0.58	0.57	0.59
Maintenance	0.41	0.50	0.51	0.45	0.44	0.44	0.45
Subtotal	1.08	1.14	1.17	1.04	1.02	1.01	1.04
Fuel	2.20	3.33	3.04	2.96	3.02	3.20	3.07
Total Production Expenses	3.28	4.47	4.21	4.00	4.04	4.21	4.11
Estimated Fixed Charges	2.83	3.13	3.60	3.55	3.44	3.61	4.00
Allocated Administrative & General Expenses	0.22	.23	.23	.21	.20	.20	.21
Total Estimated Cost	6.33	7.83	8.04	7.76	7.68	8.02	8.32
Average Heat Rate—Btu per Net Kwh	16,400	12,900	12,200	11,700	11,460	11,365	11,100
Average Fuel Cost—Cents per Million Btu	13.4	25.8	24.9	25.4	26.4	28.1	27.6
Approximate Average Annual Plant Factor	40%	60%	57%	58%	59%	59%	54%
Total Capacity—Million Kilowatts	25.2	60.0	68.1	75.4	79.5	85.7	95.2
Total Cost of Plants—Millions	\$2369	\$7533	\$8728	\$9900	\$10,589	\$11,370	\$12,696
Average Cost Per Kilowatt (Name-Plate)	\$96	\$125	\$128	\$131	\$133	\$133	\$133
Engineering-News Record Construction Cost Index	100	248	260	273	286	299	314
Average Hourly Earnings—Electric Utilities (U. S. Bureau of Labor Statistics)	\$0.80	\$1.97	\$2.05	\$2.14	\$2.25	\$2.35	\$2.38

follows an accounting pattern for reporting the annual results of electric utility operations, in accordance with the general categories of "Operating Revenues," "Operating Expenses," "Operating Income," "Income Deductions," and "Net Income." In other words, the accountants, at the end of the year, do not provide a specific figure labeled "Annual Fixed Charges" which is essential for the engineer's evaluation studies and analyses. However, all of the ingredients are present so that these "Fixed Charges" can be properly determined and related to the total investment. Then a reasonable allocation thereof can be made to the investment in "Steam Power Production" facilities.

Number of Plants, Average Size, and Historical Costs

Fig. 1 shows, graphically through four charts, the number of steam-electric plants, the total capacity, average plant size, and weighted average historical cost per kw of capacity (name-plate) for these Class A and B Utilities for the nineteen year period, 1940 through 1958.

During the period 1941 to 1958 inclusive, 266 new steam plants were placed in operation and 229 old plants were retired. Of these 266 plants, 81 were placed in service during the 5 year period, 1954 through 1958, while 83 of the old plants were being retired. The total number of plants increased about 5 per cent while the average plant size increased from 39 to 137 Mw or about 300 per cent between 1940 and 1958.

The average unit size installed by the Class A and B utilities during the five year period was approximately 100 Mw. In 1958 it was 130 Mw. The largest unit installed in 1954 was 220 Mw and in 1958 it was 335 Mw. As of the close of 1958, the total industry had 46 plants of over 500 Mws with six of these having over 1000 Mw installed capacity.

The chart, Fig. 1-c, reveals two interesting points, first the effects of postwar inflation during the first following decade, and second a general leveling off in the investment cost per kilowatt of capacity, since 1955. A contributing factor that must not be overlooked, because of its effect on the average cost per kilowatt of capacity, is the up-rating of many generating units in the past few years to reflect the generator maximum hydrogen operating pressures. Nonetheless, actual progress in reducing construction costs is being made throughout the nation with the larger units, outdoor type construction and the many other design and construction features which stress cost reductions.

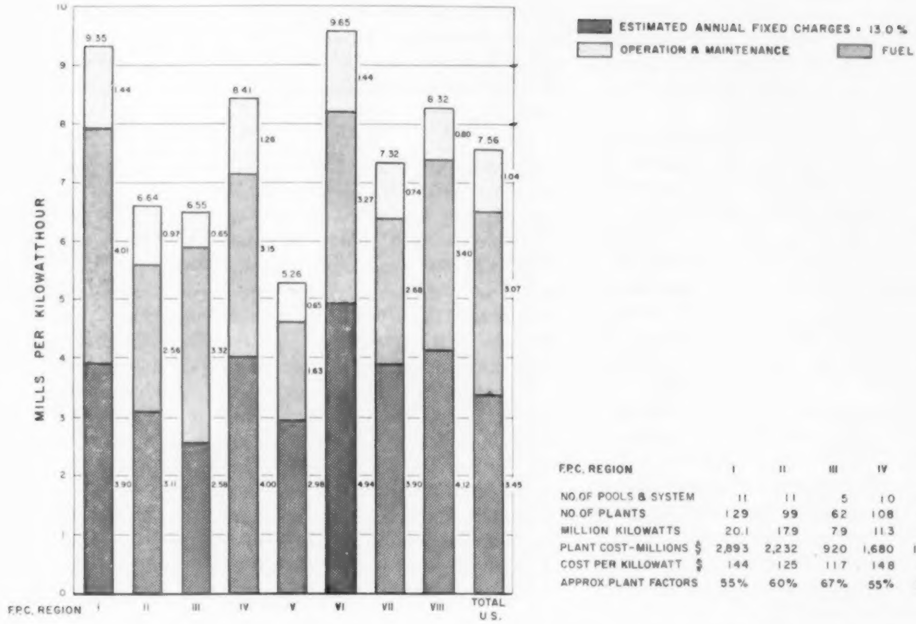
Average Production Costs—1953 to 1958, Inclusive

Table I gives on a net kilowatthour basis the total cost of producing power by the steam plants in Fig. 1 for the years 1940 and 1953, the last year in the previous paper, and each of the five years 1954 through 1958. Pertinent supporting data on heat rates, fuel costs, plant factors and investment cost have been included to round out the comparative record. Estimated Annual Fixed Charge rates of $10^{1}/_{2}$ per cent for 1940, $12^{1}/_{2}$ per cent for 1953, 13 per cent for 1954, 1955 and 1956, and $13^{1}/_{2}$ per cent for 1957 and 1958 have been used. Depreciation is included in these rates on a sinking fund basis. Such rates appear to be reasonable although it should be understood that they are estimated averages for the whole and are not necessarily applicable to any one system, company or plant.

The increase in the total kwhr cost from 7.83 mills in 1953 to 8.32 mills in 1958 is chargeable to increased Annual Fixed Charges and to fuel costs. An increase of 1 per cent in the estimated Annual Fixed Charges rate applied to a slightly higher investment cost, plus slightly higher fuel costs and a 6 per cent lower average annual plant factor increased the kwhr cost 0.49 mill or in round numbers 6 per cent.

The better heat rate in 1958 helped hold down the total cost per kwhr but not quite enough. This 1958 heat rate represented a 14 per cent improvement over the five year span. Salaries and wages which are 60 to 80 per cent of the operating and maintenance expenses, after excluding fuel, increased 41 cents per man-hour, or 21 per cent during the same period. Yet, operating and maintenance expenses per kwhr in the affected time were down 0.10 mill or 9 per cent. Improved operating and maintenance procedures and practices are reflected in these results. As a general proposition, taxes, interest costs and fuel transportation costs cannot be called controllable costs.

Although all construction costs continue to increase,



F.P.C. REGION	I	II	III	IV	V	VI	VII	VIII	TOTAL U.S.
NO. OF POOLS & SYSTEM	11	11	5	10	10	4	1	5	57
NO. OF PLANTS	129	99	62	108	102	30	5	31	566
MILLION KILOWATTS	20.1	17.9	7.9	11.3	9.7	0.7	0.4	5.5	73.5
PLANT COST-MILLIONS $	2,893	2,232	920	1,680	1,073	122	60	704	9,684
COST PER KILLOWATT $	144	125	117	148	118	164	164	128	132
APPROX PLANT FACTORS	55%	60%	67%	55%	55%	49%	62%	46%	57%

Fig. 2—Total cost of steam-electric power by regions—1956 (57 privately owned power pools and integrated systems)

the average historical investment cost per kw (nameplate) increased only $8, i.e., from $125 to $133, while the total capacity increased over 50 per cent. From the data in Table I it can be calculated, roughly of course, that the average cost of the 35 million kw placed in service during the five years was slightly less than $150 per kw. The retirements of old capacity during these years were quite small and would not carry any appreciable weight in making the above calculation.

In summing up these national average costs for the Class A and B utilities we see an excellent example of successfully combating inflation! In 1953 the Steam Power Production Expenses were 43.9 per cent of the total Electric Operating Expenses of these utilities and in 1958 they were 43.8 per cent. Top management should be pleased with their steam power production departments. This may also be said in view of all that has occurred during the 19 year period—the 1958 costs do not look very bad when compared with the 1940 costs.

Regional Costs—1956, 1957 and 1958

Frequently, valid exception is taken to the overall national average costs because of inherent regional or area differences, local considerations and other factors. Higher construction costs and operating labor costs in the metropolitan areas are examples of such differences. Fuel transportation costs are often equal to the fuel cost at the source for the plants distant from such sources. Climatic conditions and geographical location may have considerable bearing on construction costs as well as on operations. System loads and load characteristics vary in different areas and pooling operations are not standardized.

In order to overcome some of these objections, the cost data in Table I have been broken down on a regional basis for three years, 1956, 1957, and 1958, in Fig. 2, 3, and 4, respectively. The eight regions used by the Federal Power Commission in its power supply and requirement studies and reports were used. The map, Fig. 6, outlines these power regions and their subdivisions, the power supply areas.

The regional coverage is not 100 per cent complete. However, the 53 power pools and integrated systems account for approximately 90 per cent of the Class A and B steam capacity and net generation given in Table I. The 57 pools in 1956 agree with the 53 pools in 1957 and 1958. The power pool and the interconnected, integrated system basis on which the data were initially compiled gives a reasonably accurate picture for each of the eight regions because it includes all of the plants, old and new, owned by the utilities in the 53 pools or systems. The availability of hydroelectric power, privately or publicly-owned, for firm or peaking use in the regions is reflected in the regional costs.

The lowest total costs for each of the three years are in Region V which includes the southwestern gas-producing areas where fuel is still the cheapest. Outdoor type construction and the absence of coal handling and burning equipment combine to reduce construction costs and annual fixed charges. At the same time, the gas-burning boilers reduce operating labor requirements and maintenance costs are normally lower where there is no coal handling and preparation equipment to maintain.

Regions I, II, IV, and V have small amounts of hydroelectric capacity which in most cases is used for peaking purposes. In regions III, V, VI, and VII the hydroelectric capacity owned and operated by the publicly-owned utilities exceeds the privately-owned hydro

capacity. However, some of the output is available for use in the privately-owned systems. A good water year ordinarily means lower total production expenses for steam-power in the areas where such hydro power is available for integration with steam power.

Highest total costs are in Region VI with the most sparsely populated areas and the lowest regional industrial development to date. The steam power plants are fewer and much smaller and the individual units are considerably smaller than in other regions. Annual plant factors are lower due in part to available hydro capacity and, also, to less industrial load. It all adds up to the highest cost steam-electric power. The picture is beginning to change as plans are now under way for bigger plants with 100 to 150 Mw units and more high voltage transmission ties.

Region I costs reflect high operating labor costs, more relatively older capacity with higher heat rates and higher fuel costs due to transportation costs. Region I has virtually no fuel sources within its boundaries. On the other hand, the much lower kwhr fuel costs in Region II can be attributed to the vast coal resources of Pennsylvania, West Virginia, Ohio,and Indiana as well as the postwar development of the large efficient plants at or near the mines in this Region.

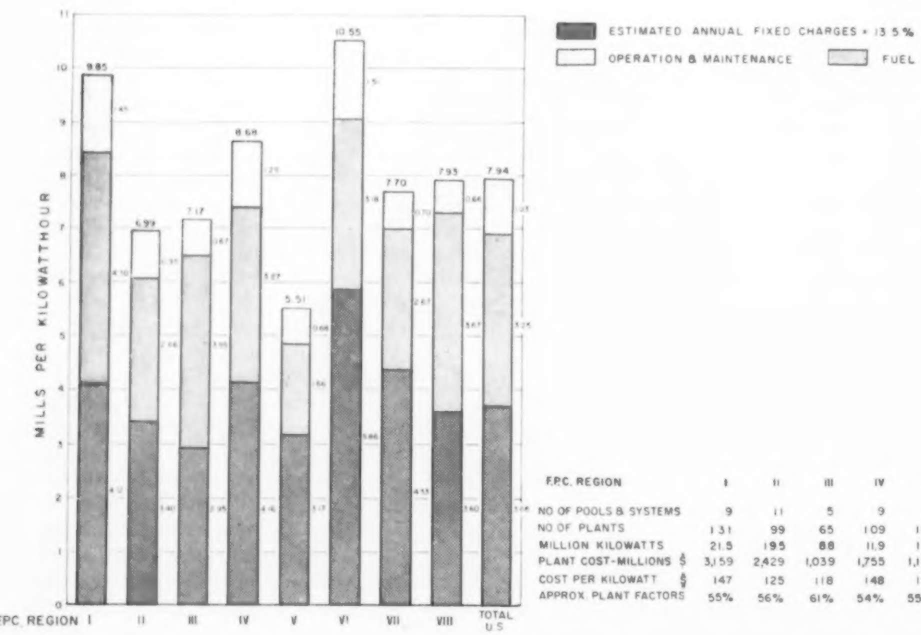
Minemouth plants and Extra High Voltage Transmission (EHV) are beginning to make their influence felt, and the next few years we will see more of these economical combinations. The adage "It is cheaper to ship coal by wire than to haul the coal by conventional transportation methods" appears to be coming into its own.

To summarize these regional unit costs for the three year period—They naturally follow the general pattern of national average costs in Table I, but, at the same time, reflect some sharp differences in fuel costs, construction costs, annual plant factors, heat rates, operating labor costs and system load factors for the eight regions.

Representative Regional Plants in 1958

An example of the costs for a modern, low cost, but not necessarily the lowest cost, plant for each of the eight regions logically follows Figs. 2, 3, and 4. Table II accomplishes this using 1958 cost data. These are large unit, postwar base-loaded plants with the low kilowatthour fuel costs. The eight plants are multiple-unit installations with all units in operation during the full year. Most of these plants have still much larger units under construction for service in the near future. The cost of the Region IV plant includes substantial costs for a 250 Mw unit which went into service in January 1959. Some equally representative modern plants were rejected for this sample because new units were placed in service during the year which result in the temporary distortion of unit costs. It is evident that this picture is subject to change almost every year in all eight regions. New, large units and plants going into service during 1959 through 1961, with still higher pressures and temperatures, will result in considerably improved heat rates in Regions IV, V, VI and VII and, also, in some lower unit investment costs in some of the regions.

The major factors entering into total costs per kwhr for these above average plants are easily recognized. The effects of investment cost per kilowatt of capacity (name plate or net capability) and annual plant factor on the fixed charges component are obvious. The impact of delivered fuel cost and the plant heat rate on



F.P.C. REGION	I	II	III	IV	V	VI	VII	VIII	TOTAL U.S.
NO OF POOLS & SYSTEMS	9	11	5	9	9	4	1	5	53
NO OF PLANTS	131	99	65	109	106	32	5	32	579
MILLION KILOWATTS	21.5	19.5	8.8	11.9	10.1	0.9	0.5	6.0	79.2
PLANT COST-MILLIONS $	3,159	2,429	1,039	1,755	1,154	146	74	757	10,513
COST PER KILOWATT $	147	125	118	148	114	169	155	125	133
APPROX. PLANT FACTORS	55%	56%	61%	54%	55%	44%	64%	53%	56%

Fig. 3—Total cost of steam-electric power by regions—1957 (53 privately- owned power pools and integrated systems)

the kwhr cost is readily apparent. Incidentally, the delivered fuel costs generally include any stocking and handling costs incurred at the plant. In other words, for coal and oil they are usually slightly higher than the actual delivered costs. Also, many of the costs reflect ash handling and disposal expenses.

A word of caution about the maintenance unit costs is in order. It is generally recognized that a single year's costs for a plant may not be representative of average maintenance costs. Average costs for a three, or preferably a five, year period should be, in most instances, more indicative of what may be expected as average experience. Since they reflect the costs for many plants and units of various ages, the maintenance costs shown in Fig. 2, 3, and 4 should be considered as more representative.

It will be observed that the total costs in Table II and also in Figs. 2, 3, and 4 do not include the allocated "Administrative and General Expenses" included in the Table I totals. In making any comparisons, the former costs should be increased by approximately 20% of the operation and maintenance costs to make them comparable with Table I unit costs.

Fuel Costs—Coal

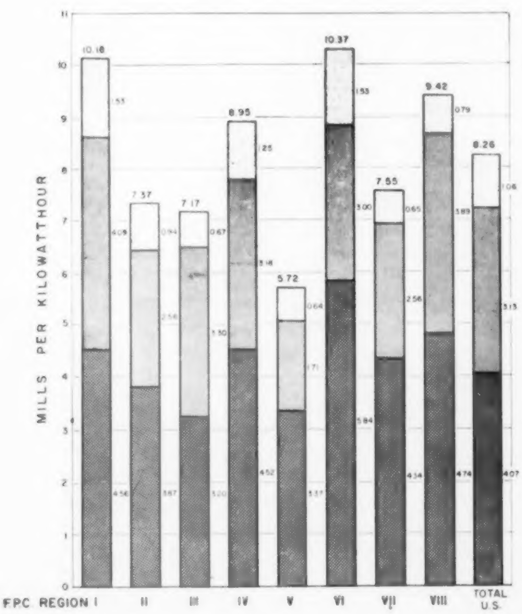
Table III shows the cost of fuel for two typical plants in each of the eight FPC Regions, except No. VII where one is given, from 1940 to date. These are annual average costs in cents per million Btu as burned. The coal and oil costs include handling costs after delivery at the plant. The gas costs given for Region V and the "pipe-line delivery" plant in Region VIII are firm gas costs. The oil-gas burning plant in Region VII burns gas "when available," with oil being the prime fuel. Efforts are under way to increase the amount of gas for power production in Region VIII.

Coal is and has been over the years the principal fuel for steam power production. Our coal resources are the most abundant of the fossil fuels. In recent years, coal has accounted for 65 per cent to 70 per cent of the industry's total generation. Since World War II, natural gas has become the second fuel in terms of usage. Between 20 per cent and 25 per cent of the generation is now by gas. The balance goes to oil.

The cost of coal at the mine for the large users such as electric utilities, who are today the coal industry's No. 1 customer group, has remained fairly stable over the past decade and even more stable during the past five years.

In view of continuing inflation and the high wage scales in the coal industry, how has this been done? An awakened industry has modernized its mining methods through mechanization and electrification of production facilities. Competition from other fuels, real and potential, including the possibilities of the uranium-fired reactor, has resulted in progress which may be expressed in terms of the average production per man-day—11.3 tons today versus 8.2 tons per man-day in 1953 and 5.2 tons in 1940. This goes a long way in explaining cost at the mine. Transportation costs are not readily explained.

Historically, the railroads have hauled most of the coal to the power plants. Rail freight rates, generally speaking, have increased slightly over 100 per cent since 1946. This has created a serious problem for the coal operators and the electric utilities. When the freight charges per ton approach and pass the per ton cost at the mine, it is time for action. Where possible, new plants have and are being built at the mines or as close to the mines as possible. Of course, this is not possible in many areas. Water-borne coal on the navigable inland rivers, as well as along the Eastern seaboard,



F.P.C. REGION	I	II	III	IV	V	VI	VII	VIII	TOTAL U.S.
NO. OF POOLS & SYSTEMS	9	11	5	9	9	4	1	5	53
NO. OF PLANTS	136	110	69	119	109	32	5	35	615
MILLION KILOWATTS	23.8	21.8	10.4	13.3	12.1	0.9	0.5	7.0	89.8
PLANT COST-MILLIONS $	3,507	2,759	1,224	1,975	1,301	157	74	867	11,864
COST PER KILOWATT $	147	127	118	149	108	172	155	124	132
APPROX. PLANT FACTORS	51%	54%	62%	54%	54%	47%	55%	43%	53%

Fig. 4—Total cost of steam-electric power by regions—1958 (53 privately-owned power pools and integrated systems)

TABLE II—REPRESENTATIVE MODERN PLANTS FOR EACH REGION, CLASS A AND B PRIVATELY-OWNED UTILITIES—1958

FPC Region →	I	II	III	IV	V	VI	VII	VIII
Plant Size—Megawatts*	320	610	250	250	306	232	166	332.5
Plant—Net Capability—MW	408	595	270	262	319	240	166	350
Plant—Commercial Operation	1952–1954	1950–1952	1954	1953, '54	1951, '53; '57	1950–1955	1954, '57	1955, '57
Number of Units	4	4	2	2	3	4	2	2
Pressures and Temperature	1450 psi; 1000°/1050°	2000 psi; 1050/1000°	1800 psi; 1000°/1000°	1250 psi; 950°/950°	1-1250 psi; 950° 2-1450 psi; 1000°/1000°	3-850 psi; 900° 1-1450 psi; 1000°	1250 psi; 950° 1450 psi; 1000°/1000°	1800 psi; 1000°/1000°
Fuel	Pulv. Coal	Pulv. Coal	Pulv. Coal	Pulv. Coal Nat. Gas†	Gas	Gas-Pulv. Coal	Pulv. Coal	Oil/Gas
Fuel Cost—Cents per Million Btu	37.50	19.47	22.66	C-22.61 Gas-20.41	12.72	Gas, 19.10; Coal, 27.33	20.85	Oil, 36.50; gas, 31.55
Heat Rate—Btu per Net Kwhr	9455	9398	9675	10,262	10,511	11,849	10,662	9673
Annual Plant Factor	81%	73%	97%	91%	80%	58%	73%	77%
Plant Cost—Millions	$58.2	$64.0	$31.9	$48.9	$28.7	$34.6	$25.5	$39.2
Cost Per Kilowatt*	$182	$105	$127	$196‡	$94	$149	$144	$118
Type Construction	Conv.	Conv.	Conv.	O.D. Boilers	Outdoor	O.D. Boilers	Outdoor	Outdoor
No. of Plant Employees	138	248	97	164	57	61	51	28
			Mills Per Kilowatthour					
Production Expenses								
Operation	0.32	0.20	0.21	0.44	0.11	0.42	0.28	0.19
Maintenance	0.26	0.29	0.10	0.41	0.08	0.16	0.16	0.13
Subtotal	0.58	0.49	0.31	0.85	0.19	0.58	0.44	0.32
Fuel	3.57	1.83	2.19	2.28	1.22	2.43	2.27	3.35
Total Production Expenses	4.15	2.32	2.50	3.13	1.41	3.01	2.71	3.67
Estimated Fixed Charges	3.46	2.21	2.03	3.29	1.80	3.98	3.37	2.35
Total Estimated Cost	7.61	4.53	4.53	6.42	3.21	6.99	6.08	6.02

* Nominal name plate ratings.
† Secondary fuel, when and if available.
‡ Includes substantial expenditures for Unit No. 3.

picks up in tonnage. The Ohio, Mississippi, and Tennessee rivers carry more coal each year. Truck haul in gigantic coal haulers from the mines to the plants is now commonplace in Georgia, Illinois, Ohio, Pennsylvania, Alabama, Tennessee, and Wyoming.

TVA recently signed a 17 year coal contract for the delivery of 65 million tons to a new steam plant that will be built in the coal fields of western Kentucky. Truck delivery over a privately-owned road is planned, at least, for the early years of operation of the first unit which will be the industry's first 600 megawatt unit.

A 110 mile pipeline was placed in service in 1958 which, it is reported, is now delivering coal at the rate of 1.25 million tons per year. This line from Cadiz, Ohio, to Cleveland, delivers coal to the Eastlake plant of the Cleveland Electric Illuminating Company. There are persistent rumors that a new, and much larger coal pipeline connecting Western Pennsylvania mines and the New York City area will be built. One thing that appears to favor this project is that it might possibly use an existing right-of-way in which one of the major natural gas pipeline companies has a large natural gas line. Rights-of-way for all uses are difficult to obtain and quite expensive and are becoming more costly each year as present owners assess their land values.

The November 16, 1959 issue of the *Electrical World* carried a news story on the possibilities of a second, much larger pipeline from the Southern Ohio coal fields to a terminus at Ashtabula, Ohio, on Lake Erie for utility coal. If a railroad company joins the undertaking, the right-of-way problem should be solved quite sensibly.

Conveyor belt movement of coal, except for very short distances between the mines and nearby plants, has not materialized. This does not mean that this innovation has been permanently discarded. Again, steel companies have the idea under consideration for ore movements. There could be dual usage of such a system some day. In this age, what first appears to be a fantastic pipe-dream, often has a tendency to become a money-saving reality.

Big power plants measure their daily coal requirements in terms of 25 to 100 or more carloads per day. The railroads, especially the so-called coal-carriers, have and are making concessions in their rates to retain this year-round tonnage. Such adjustments, subject to regulatory approvals, are occurring in the Southeastern states, in the New York and Chicago areas, in Ohio and other parts of the country. After several years, it would ap-

TABLE III—FUEL COSTS—BY REGIONS—1940 TO 1958, CENTS PER MILLION BTU (AS BURNED)

	1940	1945	1950	1953	1954	1955	1956	1957	1958
Region I									
Oil—Tidewater delivery	21.60	31.12	36.60	38.43	39.70	43.30	42.40	48.20	38.30
Coal—Rail delivery	14.25	19.60	29.20	31.15	30.10	29.22	31.20	33.70	34.80
Region II									
Coal—Mine Mouth	8.20	13.02	15.77	16.37	16.59	16.06	16.51	17.57	18.22
Coal—Rail/water delivery	13.80	21.40	31.50	30.00	28.90	27.76	30.20	31.76	31.86
Region III									
Coal—Minemouth	11.16	18.27	19.09	18.64	16.63	15.34	16.34	17.57	18.87
Oil—Tidewater delivery	17.80	25.90	31.20	31.51	33.60	35.40	38.60	45.30	38.60
Region IV									
Coal—Short rail haul	11.41	13.42	21.86	21.21	20.06	20.14	21.13	22.15	21.75
Coal—Rail-water delivery	18.50	22.08	31.69	30.95	29.50	28.44	29.48	28.39	27.05
Region V									
Gas—Producing area	7.00	5.80	6.32	7.02	6.18	6.39	6.53	6.89	17.69
Gas—Producing area	9.30	7.80	8.00	10.00	9.10	10.66	11.90	13.60	14.20
Region VI									
Coal—Short rail haul	12.20	15.0	23.07	24.24	24.52	25.40	26.22	27.01	27.31
Lignite—Short rail haul	18.50	21.31	33.45	32.11	32.02	31.75	31.61	32.02	33.22
Region VII									
Coal—Short rail haul	13.17	18.15	28.01	26.29	25.42	25.79	26.34	28.09	26.61
Region VIII									
Oil & Gas—Water & pipeline	15.5/12.7	18.8/12.1	23.00/18.28	32.20/18.10	32.34/18.49	29.67/21.09	35.71/21.76	45.11/22.76	44.00/27.80
Gas—Pipeline delivery	19.11	19.41	16.30	21.78	21.58	24.21	24.29	24.36	27.23

pear that we are coming to what has been referred to as a train-load rate for users who can take and handle the very large deliveries directly from the mines. The writer recalls discussing the possibilities of this idea about twenty years ago.

What does all of this add up to costwise for the near future, the next five years, or perhaps even ten years? Many predictions have been made and publicized since the nuclear reactor programs were inaugurated. Naturally, there have been some wide differences of opinion. Another guess will not do any harm. It appears reasonable to predict that, barring war or extreme inflation, the delivered price of coal to the large steam power plants will not increase materially between now and 1965 or even 1970. This opinion gives consideration to all of the above-mentioned factors as they affect prices at the mine and transportation costs.

One point stands out—very large mine-mouth plants and EHV transmission can be an effective means of keeping fuel costs down over a rather large part of the nation. After the study of appropriate maps that, when considered together, give a comprehensive picture of the location of fuel reserves, existing plants and high voltage transmission lines and adequate water supplies, it is not too difficult to see the future possibilities. Further integration of these four factors is reasonable and can be quite practical. Earlier mention was made of the 28 very large units, 300 to 600 megawatts now being installed. Nine of these units are being installed at or quite near the fuel source. Seven of the nine are coal-fired!

Fuel Costs—Natural Gas

Natural gas is the base fuel in the gas producing areas, most of which are in Region V. In other parts of the country it is burned on a "wherever" and "whenever" available basis. This is usually during the summer months when the house heating customers and industrial users are not fully utilizing at maximum capabilities the network of pipelines, which now criss-cross most of the nation. In recent years gas has become available to several plants in Southern New England and the New York City area on this "if-and-when" available basis. Quite recently it was introduced in the Florida Peninsula where it is becoming available to the utilities for boiler fuel at some of their plants.

However, the price of gas has been increasing steadily over the past decade in the producing areas as well as in the more distant areas served by the pipelines. The greater the expansion of the pipeline systems the greater the demands and hence the higher costs. The old gas-supply contracts for power generation, most of which have expired or are now expiring, are being replaced with new contracts that double or even treble the price of 20 years ago. Furthermore, these new contracts usually contain escalation clauses that will, over the contract period, increase the initial price materially. Table III gas costs are illustrative of these steadily increasing prices.

As insurance against these continuing price increases some of the Southwestern utilities are designing their new plants so that they can be converted for burning coal if necessary in the future. These plants are located on or near the navigable waterways. After all, there is a definite limit to what will be paid for the gas.

Fuel Costs—Oil

The price of oil is not easy to explain or even to understand. The oil burned in the power plant is a heavy residual oil, a refinery product. The price quoted the large user is usually a delivered price and delivery to this large user is by boat, the tanker or barge. Oil is not delivered to the large power plant by pipeline except for short distances. Rail or truck deliveries for large plants are not common.

The market price is up or down according to crude oil production, refinery operations, available residual supplies and competitive factors. Since oil is produced in many parts of the world and is imported to as well as exported from the U. S. the price structure is rather complex. Import quotas, dollar rate of exchange and world politics effect pricing as well as the laws of supply and demand. The temporary closing of the Suez Canal in 1956 is an example of an unusual situation that can have a direct bearing on the cost of oil delivered to a U. S. power plant.

Oil can be and is generally competitive with coal at tidewater along the Atlantic Coast, particularly from New York to the northward and from Charleston, S. C. to the south. Oil and gas are burned on the Pacific Coast without any competition thus far from coal. Transportation costs have precluded the use of coal. This picture could change to some extent in the future with the development of western coal fields and adjusted freight rates.

To conclude the fuel story it is not difficult to understand why so much attention is being directed to future fuel supplies and the problem of getting the fuel to these large plants or, to put it another way, of getting the plants closer to the fuel source.

Plant Thermal Efficiencies

Ten years ago about one company in one hundred mentioned the thermal efficiencies of its plants in the annual stockholder's reports. Instead, mention was made of rapidly increasing fuel usage, the cost per ton or other unit and the total fuel bill for the year. Today there must be a considerable number of stockholders who understand, in a vague but self-satisfied manner, the technical terms, "plant heat rate" and the "system heat rate" because more and more of these reports for the layman readers proudly, and properly so, call attention to the company's average heat rate for the year and the number of plants or units with heat rates of less than 10,000 or 9500 Btu per kilowatthour. Mr. Stockholder gets the general idea that there is a definite relationship between his company's heat rate and its annual fuel bill which he knows is a major expense item. It might even have some bearing on the size of his quarterly dividend check. After all, in 1958 the fuel bill of the Class A and B utilities accounted for one-third of their total operating expenses.

Fig. 5 illustrates the improvement in annual heat rates, i.e., the number of Btu's required to produce one kwhr for all U. S. plants, large and small, old and new, from 1940 through 1958. It also shows the heat rate for the most efficient plant operated for the full year during this time. From 16,400 Btu in 1940 to 11,100 Btu in 1958 represents an outstanding improvement of 33 per cent. The best plant of 1958 bettered the best plant of 1940 almost 15 per cent.

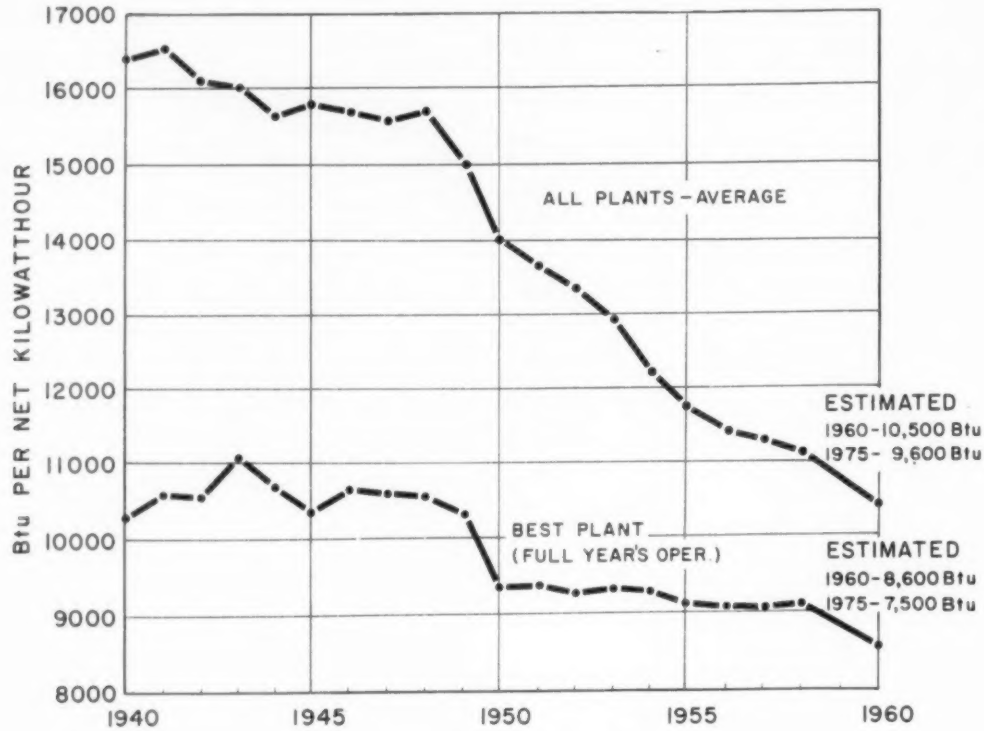


Fig. 5—Steam plant heat rates—1940 to 1958

As the new large, high pressure, high temperature reheat units come on the line each year many old, smaller low pressure units are relegated to stand-by service. The effect on the heat rates and hence the kwhr fuel costs is quite noticeable. This is pointed out in the tenth and eleventh Annual Supplements to the FPC's annual publication, "Steam-Electric Plant Construction Cost and Annual Production Expenses" for 1957 and 1958, respectively. In 1957 there were 51 of these new plants with large reheat units having plant heat rates of less than 10,000 Btu that constituted 25 per cent of the reported steam-electric generating capacity and 31 per cent of the generation. In 1958 there were 56 plants in this category representing 25 per cent of the capacity and 34 per cent of the generation. Further gains may be expected each year. The plants reported in these Annual Supplements represent almost 90 per cent of the industry's total steam-electric generating capacity and 94 per cent of the annual kwhr production. All of this is quite remarkable when it is remembered that the best plant performance in 1940 was 10,729 Btu and that it was not until 1950 that two plants for the first time crossed the old barrier of 10,000 Btu per kilowatthour.

It follows, that if the individual plant heat rate is of so much importance in arriving at costs for a single plant the average annual heat rate for all of the plants in a system or pool is of much greater importance. Three major systems in 1958 had average system heat rates of less than 10,000 Btu—the publicly-owned TVA System and the privately-owned Consumers Power Company (Michigan) and The American Electric Power Company, Inc. System operating in Virginia, West Virginia, Ohio, Michigan, and Indiana. These outstanding performances were 9760 Btu, 9896 Btu, and 9921 Btu, respectively. It is quite likely that there will be more such systems in 1959, with further additions each following year. The national average heat rate of 11,100 Btu in 1958 should be reduced to 10,500 Btu or less in the next five years. A 9600 Btu rate is predicted for 1975.

The electric power industry is now burning in excess of 225 million tons of coal, including gas and oil as coal equivalents, per year in the generation of some 500 billion kwhr. In 1975 it is conservatively estimated that the conventional steam-electric generation will be well over one trillion kwhr. The fuel savings, first, as one of our exhaustible natural resources, and second, in terms of dollars cost, due to an estimated heat rate improvement of 15% between 1958 and 1975 will be a real power plant engineering achievement.

Automation

The centralizing of the operating controls for the boiler and turbine-generator and their auxiliaries has been an outstanding engineering accomplishment during the past decade. The quiet, well-lighted and organized, air-conditioned central control room for two or three boiler-turbine-generator unit installations is here to stay. Operating manpower requirements have been very materially reduced and operating efficiencies have increased. Safety methods have improved.

The next step has been the installation of electronic computers in the load dispatching centers, the engineering offices and the plants to simplify the task of making the endless calculations that are so essential to the

Fig. 6—FPC map showing power supply areas and regions

economical dispatch of power. This is continuing and we are now on the threshold of a third step which fits in quite naturally with our new "space" age.

Complete automatic operation of the modern steam-electric plant! This does not mean unattended plants—it means less manpower involved in starting, running, and taking the machines off the line. Of greater importance than manpower savings is the reduction of the chances for human errors in operations. As generating units become larger and more complex the costs of operating errors become more and more expensive. In fact accidents are just too expensive to have in these plants.

Computer control is well on its way in many facets of our industrial picture and the electric utilities have been prompt in exploring the possible use of these ingenious machines in all phases of their operations. So the first of the full automatically controlled plants is now under construction—the Little Gypsy plant of the Middle South Utilities System in Louisiana. Initially, it will have a single 200 Mw 2000 psi, 1000F/1000F reheat, gas-fired unit. According to the public announcements and articles appearing in the technical journals it will normally be started, stopped, and placed back in operation automatically. In case of trouble or emergency it will be stopped and with the trouble or emergency located and cleared it will be started up again, all automatically through an elaborate electronic computer system.

A second such installation has been ordered for the control and operation of the third and fourth 200 Mw units in the Southern California Edison Co.'s Huntington Beach plant. Unquestionably, these two pioneering installations will be followed by others.

Of course the answer to this type of automation is found in the safety element, so vital in plant and system operations for operating personnel and equipment. The split second decisions that are often required in operating these complex plants can, in the opinion of many engineers, best be left to these computer control systems functioning under highly competent human supervision. The computer control becomes insurance against human errors in an age where reliable uninterrupted service is taken for granted.

Nuclear Power and the Future

Since 1953 a considerable amount of the glamour and urgent appeal has worn off of the immediate possibilities of nuclear power. After all is said and done, the nuclear reactor is only a replacement for the conventional steam boiler that produces steam which in turn is converted to mechanical energy and finally to electric energy. As a matter of fact, it isn't nuclear power. It is nuclear reactor-produced steam. The generator still produces the same 60 cycle alternating current.

The reactor will find its place in the scheme of things in time but only after a lot of extended hard work and continued research and development. All one has to do in order to arrive at this conclusion is to study the history of conventional steam power over the past six decades. It took 50 years to attain the 10,000 Btu heat rate! The same old problems of pressures and temperatures, corrosion, and suitable metals have to be solved plus several new and special problems involving only the nuclear fuel, its processing, burning, and reprocessing, waste disposal, etc., that are not involved with the conventional steam generator. "Crash" programs and "overnight break-throughs" are not the answer. There are too many problems yet to be solved satisfactorily. As has aptly been said the economic production of nuclear power will come through the processes of evolution not revolution.

At this time, there are five experimental reactors in operation for the production of steam for electric power. The largest is the 60/100 Mw Shippingport plant. A few more experimental plants will come into operation in 1960, 1961, and 1962. However, we do not yet have any realistic, comprehensive cost data pertaining to either construction or operation. Nor will such costs be available in the next two or three years. In time we will have useful construction and operating cost data.

In the meantime, we must be patient and not ignore the continuing technological advances that are being made in conventional boiler and turbine-generator design, construction and operation. Along with this it will be well to keep in mind the previously discussed possibilities of the now tested and tried Extra High

Voltage Transmission for bulk delivery of very large amounts of power from mine-mouth or wellhead plants to what used to be called distant markets. Too, there are long term economic possibilities in the development of a radically different electric generator—the magnetohydrodynamic generator which would eliminate the steam turbine and a considerable amount of related auxiliary boiler plant equipment. Here, a reactor might be used as the source of the heat instead of a fossil fuel furnace. Electric utilities have recently agreed to finance a limited amount of basic research in this long range project.

In conclusion, it must be remembered that all of the electric power customers, from the smallest home or shop to the largest industrial users, stand to gain from these continuing strenuous efforts to control and, where possible, reduce the total production costs of electric power however produced.

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Gleanings on Water Reactor Progress

At the recently concluded Annual Meeting of the ASME in Atlantic City the water reactor in nuclear energy development was discussed.

William A. Hartman, General Electric Co., and **Leonard F. C. Reichle,** Ebasco Services, Inc., presented the conceptual design for a large boiling-water-reactor power plant to start construction in July 1960. It is based largely on a study conducted for the U. S. Atomic Energy Commission and their paper was entitled "Boiling-Water-Reactor Study." The objective of the study was to identify and describe the "most promising" type of boiling-water reactor and associated complete electrical generating plant consistent with the state of the nuclear art and a schedule calling for start of construction in July 1960. In addition, a cost-size relationship of this type of nuclear power plant was estimated. A number of studies of the technical parameters involved in selecting the design are covered briefly.

It was concluded that, within the limitation of the conditions set forth as the basis for the study and on a basis for which a commercial contract could be taken, the selected BWR power plant would have the following characteristics, costs and estimated performance:

(*a*) A net electrical capability of 306 Mw.

(*b*) A dual-cycle, forced-circulation, boiling-water reactor using a single reactor and a single-tandem-compound turbine-generator with a four-flow exhaust.

(*c*) Capital costs $259 per net kw at 1959 cost levels and $284 per net kw escalated to 1963.

(*d*) Total energy costs 8.0 mills per net kwhr at 1959 cost levels and 8.6 mills per net kwhr escalated to 1963, subdivided as follows:

1. Annual fixed charges are 5.2 mills per net kwhr at 1959 cost levels and 5.7 mills per net kwhr escalated to 1963.

2. Operation and maintenance costs 0.7 mill per net kwhr, including nuclear indemnity and general and administrative expenses.

3. Fuel-cycle costs after the equilibrium fuel cycle has been established (estimated to be approximately 7 years after startup) 2.1 mills per net kwhr at 1959 cost levels and 2.2 mills per net kwhr escalated to 1963.

(*i*) Nuclear superheat technology is held not sufficiently advanced to justify its use in a large plant scheduled for start of construction in July 1960.

The proposed BWR plant is believed technically feasible, provides adequate protection against radiation hazards, is compatible with electric utility system operation and is of a size that is suitable for application to approximately 20 utility systems in the United States.

A. R. Jones, Westinghouse Electric Corp., in his paper "Another Step in Water-Reactor Plant Technology" gave a study of the technical and economic feasibility of closed-cycle water reactors. The term, closed cycle, is chosen rather than the more commonly used term, pressurized-water reactor, inasmuch as the older term implies a complete absence of boiling. As a result of the aforementioned study, it was determined that such plants are feasible in ratings up to 400 Mw electric. It was also determined that power costs reduce with increasing size up to the point where the turbine designer changes from a tandem-compound to a cross-compound machine. This occurs at a turbine-generator rating of about 360 Mw.

The costs for 200, 300 and 400-Mw plants were 9.5, 8.6 and 8.2 mills per kwhr, respectively. The power costs dropped sharply to 300 Mw, but the reduction in going on to 400 Mw is rather insignificant.

J. B. Anderson, Combustion Engineering, Inc., and **C. T. Chave,** Stone and Webster Engineering Corp., discussed "An Advanced Pressurized-Water Reactor Electric Generating Station." The most important step which can now be taken to improve pressurized-water systems consists of raising the average coolant temperature to, or near, the saturation temperature for the operating pressure. Although bulk boiling will occur in the hot regions of the core, only a very small amount of reactivity is tied up in voids at high power.

Zoning of uranium enrichment now appears to be the most desirable way of improving power distribution and decreasing the peak fuel burnup. The use of spikes of highly enriched uranium or plutonium, although presenting a more difficult design and development problem, is expected to bring correspondingly greater improvements in reactivity lifetime and lower fuel cycle cost. In the case of zoned cores, reactivity variation through life would be held relatively flat with burnable poisons and a high conversion ratio. Spiked cores would employ self-shielding of the fuel in the spikes and a high conversion ratio to achieve the same goal.

This problem of flashing in boiler feed pumps which Igor Karassik has raised in his "clinic" appearing in these volumes has evoked considerable discussion throughout the industry. Here is yet another valuable view on this matter.

Protecting Boiler Feed Pumps Against Flashing

By P. H. HARDIE*

Ebasco Services, Inc.

with comments by

IGOR J. KARASSIK† and L. E. ZABEL††

Worthington Corp. Worthington Corp.

THE writer has followed with interest the series of questions and answers in COMBUSTION entitled, "Steam Power Plant Clinic." Parts VIII and XIII in the May and November 1959 issues, dealt with anti-flash baffling in deaerators as it affects the net positive suction head (NPSH) at the boiler feed pumps. Part XIII by Mr. Karassik et al. also discusses an unusually stringent test performed by Japanese power companies on all new steam electric units. It reports a solution arrived at to protect against flashing in the boiler feed pumps when this test was performed at one Japanese station.

The writer's company is in the process of designing another steam electric plant for the same Japanese company and we are providing a different type of protection which may be of interest to others. This scheme, we believe, is more positive and provides assurance of adequate NPSH at the boiler feed pumps under any and all conditions of operation. The controls described can be adjusted to suit any particular installation.

The Japanese Test

The unusually stringent test performed by the Japanese consists in bringing a turbine generator unit rapidly up to full load and then almost immediately tripping the unit. The authors of Part XIII reported that within seconds after tripping, the boiler feed pumps lost suction. This was attributed to the anti-flash baffling in the deaerator which supplied water at saturation temperature to the boiler feed pump suction pipe, instead of water 35 F below saturation which existed in the deaerator storage tank. The fast pressure decay rate in the deaerator was due to the subsaturation temperature of the stored water. The removal of anti-flash baffling prevented flashing in the boiler feed pump suctions during subsequent tests.

However true the above, it is a fact that almost always the stored water in the deaerator is at, or very close to, saturation temperature. We know that anti-flash baffling does some good for some installations, because for several older installations, which experienced trouble from flashing, the trouble was eliminated by installation of anti-flash baffling in the deaerator storage tanks.

It is the writer's contention that for modern high pressure stations the pressure in the deaerator should not be allowed to decrease rapidly. For normal American practice, load pickup is not so rapid that the temperature of the water in the deaerator storage tank lags the saturation temperature of the steam in the deaerator, even when anti-flash baffling is used. High pressure extraction feedwater heaters are continuously discharging their drains to the deaerator storage tank at temperatures above saturation. Usually other flashing drains are discharged to this tank, which also helps to keep the water at saturation temperature during load pickup.

For the stringent Japanese test mentioned above we intend, instead of eliminating the anti-flash baffling, to recirculate enough feedwater (which is several degrees above saturation temperature in the deaerator) through the boiler feed pump recirculation lines to keep the stored water near saturation temperature. Control switches permit holding the automatically-operated valves in the recirculation lines open, even after the boiler feedwater demand is above the minimum safe flow rate for the pumps.

The Role of Controls

If a deaerator is sealed against any loss of steam after a turbine trip by means of a check valve in each supply line, the pressure can decay rapidly only if cold condensate continues to enter at too rapid a rate. In order to slow down the rate of pressure decay, two things must be done: (1) open the steam pegging††† valve; and (2) limit the rate at which cold condensate is admitted. Usually, the condensate supply to the deaerator is made responsive to deaerator storage tank level only, and the pegging control valve is responsive to low pressure in the deaera-

††† A pegging steam valve is used to supply steam from some other than the normal source to keep the deaerator pressure from dropping to or below atmospheric. Usually this valve is set to open at 5 to 10 psig.

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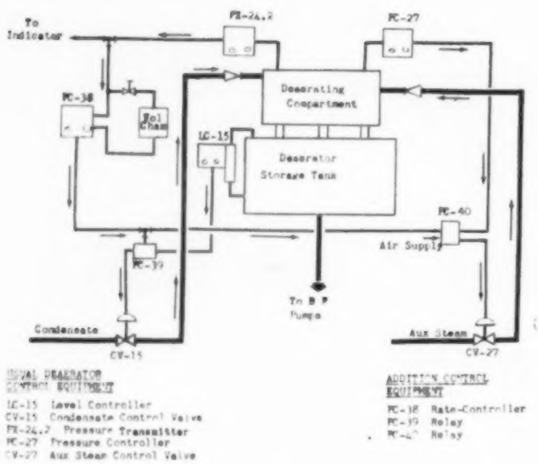

Fig. 1—Suggested deaerator controls to protect Boiler feed pumps against flashing difficulties

tor only; therefore additional controls are required.

We are providing a pressure rate-controller that will have no effect upon the pegging steam valve nor the deaerator level control when the deaerator pressure is rising or steady. However, whenever a pressure decrease occurs, the pressure rate-controller will override the normal controls, to open the pegging steam valve. Then, if the pressure continues to decrease at a rate faster than the predetermined safe rate, the rate-controller will slow the of condensate to the deaerator.

One might ask, why not let the pegging steam do the entire job? The answer is, that an extremely large quantity of auxiliary steam would be required if the condensate valve opens even a moderate amount. Large quantities of auxiliary steam usually are not available, and there is no guarantee the condensate supply valve will not open wide, if sudden shrinkage takes place in the boiler or deaerator.

With the controls described, some decrease in level of water in the deaerator storage tank may occur, due to overriding the level controller, but calculations have shown that the decrease in water level that could occur would not be serious since the boiler feedwater requirements are not great after a trip-out.

Fig. 1 shows the controls required to provide the above recommended protection against flashing. If a pneumatic pressure transmitter is provided already, the cost of the added controls, as supplied by one well known control equipment manufacturer, is only about $200. This control scheme should be used to improve safety, and not to reduce the height at which deaerators are set.

For the new Japanese station referred to above, the controls are to be set so that the pegging steam valve will open wide and the condensate valve will begin to close when the rate of pressure decrease in the deaerator reaches 4.5 psi/min. The condensate control valve will continue to move in the closing direction as the rate increases, and will reach the closed position if the rate of pressure decrease should reach 5.5 psi/min. With a deaerator sealed against back flow, and with flashed steam supplied from the stored water plus the auxiliary steam, the flow of condensate to the deaerator would be restricted, but never completely shut off by the rate-controller.

Allowable Pressure Decay

The adjustment required for the rate-controller is a function of excess NPSH provided by the elevation of the deaerator, and the time required for the water to travel from the deaerator storage tank to the boiler feed pumps. For the Japanese installation discussed above the excess NPSH is 28 ft and the time for the water to reach the pump furthest away from the deaerator is $1^1/_4$ minutes at maximum load. This would allow a pressure decay rate of 9 psi/min. However, since the rate of feed to the boiler will decrease, thereby increasing the time, the controls will be set to limit the decay rate to $^1/_2$ the maximum allowable at full load, or 4.5 psi/min.

The allowable rate of pressure decay could be higher if a smaller suction line were used, but with several pumps supplied from a common suction line there might be danger of flashing in the pump at the end of the line when one of the other pumps is started. If the suction line is small the pump being started will momentarily decrease the suction line pressure too much, thereby causing failure of the end pump.

Part XIII states, "*There is an increasing practice of withdrawing some saturated steam from the deaerator shell for building heating. This helps to increase the rate of pressure decay. . . .*" Such practice could lead to boiler feed pump flashing troubles even with no anti-flash baffling, and should be discouraged. It is essential that the deaerator be sealed against loss of steam after the extraction steam supply fails as stated above.

Some central stations use hot water from the deaerator storage tank for combustion air heating ahead of the exhaust gas preheater. When this is done the hot water circulated should be reduced to the minimum required to prevent freezing in the coils after a trip, in order to limit the amount of cold water returned to the deaerator. Other stations use hot water from the deaerator storage tank for building heating. Since this is not an essential service the recirculating pump should be tripped when the turbine trips, if the quantity being circulated is proportionally large, in order to prevent return of the cooled water to the deaerator. After the deaerator pressure has become stable again the heating system recirculating pump could be restarted.

Answer to Above Comments

By IGOR J. KARASSIK and L. E. ZABEL

We are extremely gratified to see Mr. Hardie's comments on our article. They are further proof that the subject of transient operating conditions—once a more or less mysterious problem that plagued power plant operators, but one with which these operators had to resign themselves to live—is receiving considerable attention and light. It is reasonable to expect that in the not too distant future, the thinking and the work done on this

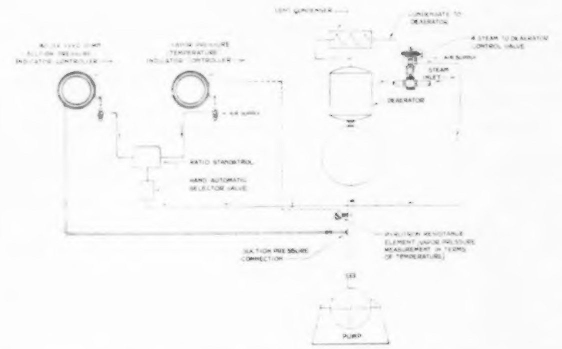

Fig. 1—A patented protection for deaerator pressure, above, operates from a difference between suction pressure and vapor pressure at the pump suction to open auxiliary steam supply

subject will relegate the problem into the "fully solved" category and the "case" will be closed.

The control described by Mr. Hardie is quite interesting. Of course, there are several types of controls which can be employed to reduce or even eliminate all the unfavorable effects of the transient conditions which follow a severe load reduction. But before we speak of these controls, we need re-examine certain premises introduced by Mr. Hardie.

He refers to the fact that the installation of anti-flash baffling eliminated troubles from flashing experienced in some older installations. Several such instances were reported to us previously. But none of the cases reported were documented with a complete second-by-second record of the pressure and temperature conditions which followed the load drop during the "residence time" period. On the other hand, the one specific instance for which one of the authors has full documentation proved very conclusively that the anti-flash baffling *does not* provide any protection for the duration of the residence time. The actual chart of the conditions that prevailed after a severe load reduction of a 100,000 kw unit was reproduced in the May issue of COMBUSTION. This evidence confirmed an analytical examination of the events: if colder water is directed to the pump suction by the anti-flash baffling, this colder water cannot be of any assistance until *after* the suction piping and the pump have been voided of the hotter water that was flowing before the load drop.

The same May issue of COMBUSTION looked into the reasons why reports existed of alleviation of troubles in units provided with anti-flash baffling. Briefly, two possible reasons can exist for this. Anti-flash baffling can lead to an appreciable stratification of the storage water. If the freshly deaerated water is insufficient to satisfy the boiler demand, the deficiency is made up from the colder storage water at the bottom of the tank. This make-up colder water may act to quench the flashing that would be taking place in the suction piping. Another possibility is that the pump still flashes, but its operation is restored to normal more rapidly than if anti-flash baffling were omitted.

Regardless of these considerations, it is demonstrable that the effect of anti-flash baffling gives insufficient protection in most cases and can lead to more serious troubles in certain installations, especially such as were described in the November issue of COMBUSTION.

Mr. Hardie places considerable reliance on the effect of high-pressure heater drains and other hot returns to the deaerators which might tend to maintain stored water nearer to saturation temperature. But in a great many cases, these returns are introduced above the overflow level, so that only saturated water goes to the storage space. Furthermore, in many plants the high-pressure heater drains are not pumped to the deaerator but are transferred by pressure difference. As a result, these drains are by-passed to the condenser at light load operation and cannot assist in maintaining the stored feedwater at saturation.

The effect of heating stored feedwater by the boiler

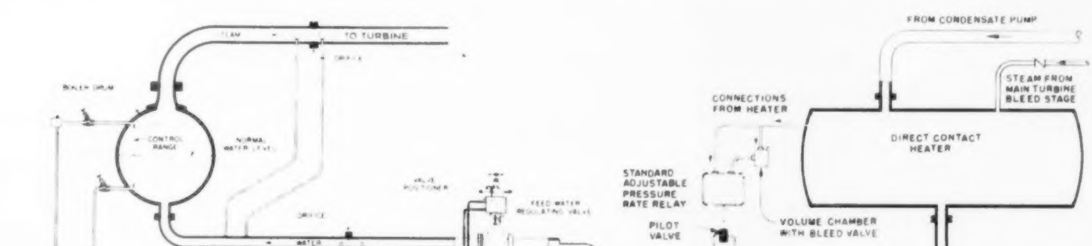

Fig. 2.—A second deaerator pressure monitor employs a pressure rate relay to regulate feedwater flow if pressure drops too fast

feed pump recirculation is minor, especially if the return to the deaerator is handled through a perforated pipe above the water level. There is also added the necessity of additional switches and controls. Finally, the expense of operating the recirculation by-pass at loads where it is not needed for pump protection may not be justifiable if other means are available to protect the installation.

Mr. Hardie's suggestion—first, to peg the deaerator pressure and, second, to limit admission of cold condensate—is effective. It might be debatable whether pegging the pressure or admitting auxiliary steam every time that the deaerator pressure is falling is necessary. One of the authors developed a relatively similar control some years ago (U. S. Patent 2,372,087, Mar. 20, 1945). This control is illustrated in Fig. 1. Essentially, it consists of measuring elements for the suction pressure at the pump suction. The difference between the two is constantly weighed against a predetermined acceptable minimum.

Any reduction of deaerator pressure which causes the available NPSH to drop below the NPSH required causes the steam valve in the auxiliary steam supply to the deaerator to open sufficiently to maintain a safe rate of deaerator pressure decay. A variation of this control utilizes the same impulse to allow a certain amount of cold condensate to by-pass the deaerator and enter directly at the boiler feed pump suction, quenching the feedwater sufficiently to restore the required NPSH.

Quite a number of these controls have been installed on deaerators both in the U. S. and abroad and have been very satisfactory in preventing any flashing even under very adverse conditions.

Another variation of this principle is illustrated on Fig. 2. Here, a pressure rate relay senses too rapid a reduction in pressure in the deaerator and utilizes this impulse to "interfere" with the feedwater regulator (U. S. Patent 2,904,018, Sept. 15, 1959). Normally, a load drop would be immediately followed by a reduction in boiler feed water flow such that the allowable rate of pressure decay in the deaerator would exceed the actual rate. Unfortunately, however, the load drop is generally followed by boiler shrinkage and the drum level impulse overrides the attempt of the feedwater flow impulse to match that of the steam flow. In the control described on Fig. 2, the impulse from the pressure rate relay nullifies the impulse from the drum level until such time that normal conditions have been re-established in the deaerator.

It can be seen, therefore, that a number of controls can be used to protect boiler feed pumps against transient conditions. But if an installation can be made safe without the need of controls by eliminating subcooling of the stored feedwater by providing a sufficiently large storage space and by using the minimum possible residence time in the suction piping, the elimination of these controls is obviously an advantage.

P. H. Hardie Replies . . .

. . . I have read with interest Mr. Karassik's comments of January 20 on my comments of January 6 on the above subject. I have no desire to continue the discussion since everyone has the right to his opinions and there is usually more than one satisfactory method of accomplishing the same result.

I would like to say, however, that I am familiar with the control scheme in Fig. 1 of Mr. Karassik's comments and I have, in the past, given consideration to its use. The reasons for deciding against it are two:

1. There has never been enough auxiliary steam available to do the job if the condensate is allowed to enter the deaerator at the same rate that feedwater is being withdrawn. For example, the Tokyo plant referred to in my comments would require 300,000 lb/hr of auxiliary steam, whereas only 50,000 lb/hr is available.
2. The cost of the controls shown in Fig. 1 is high, and the larger steam valve and piping required adds further to the cost.

Nuclear Congress Expects Biggest Meeting Ever

The 1960 Nuclear Congress and Atomic Exposition, to be held in New York City's Coliseum, April 4–7, will be the biggest in history, according to Clarke Williams, chairman. The meeting will be the biggest in total attendance, biggest in engineer attendance, offer the biggest scientific and technical programs, and present the biggest exhibit of nuclear products and services.

Reason for these claims is based on the fact that 35 per cent of the Nation's entire force of 600,000 engineers is located within 300 miles of New York City, 50.6 per cent of previous Nuclear Congress technical session attendance has been from this same area, and 87.1 per cent of attendance at previous sessions come from East of the Mississippi (which territory is easily accessible to New York). Current exhibit space sales for the 1960 Exposition already exceed the total space sold for any previous atomic meeting held in New York.

To date 91 companies and three foreign governments have reserved space for the exhibit. Newest companies to apply for space are Beryllium Corp., The Brush Beryllium Co., Combustion Engineering, Inc., Consultants Bureau, Elcore, Inc., Flanders Filters, Lockheed Nuclear Products, Marquardt Corp., Nuclear Data, Pacific Coast Engineering Co., RCA Service Co., Damascus Tube Co., Burroughs Corp., Kaman Nuclear, and Technical Measurement Corp.

The Nuclear Congress consists of the 6th Engineering and Science Conference, the 8th NICB Atomic Energy in Industry Conference, and the 6th Atomic Exposition. The Atomic Exposition is the official exhibit of the Nuclear Congress, sponsored by 28 leading engineering, scientific, management, and technical organizations who are interested in the peaceful use of atomic energy.

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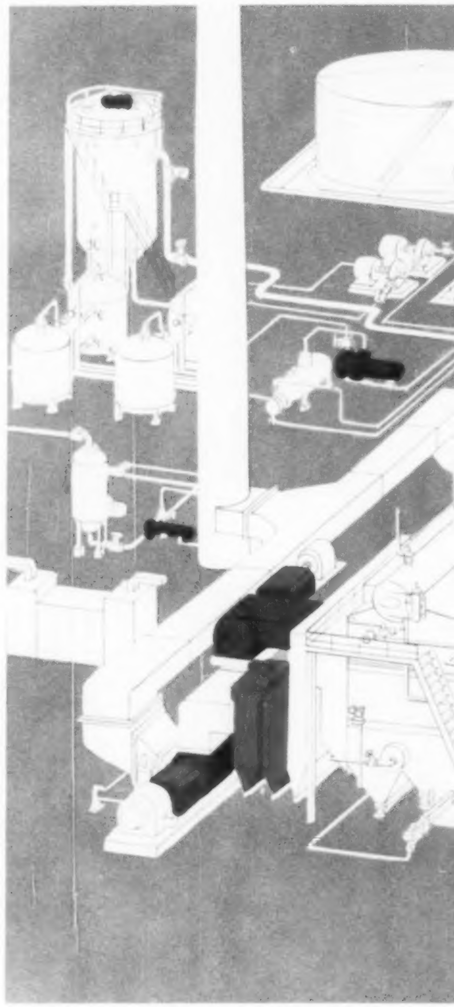
1959

Early in 1959 three American-Standard divisions—American Blower, Ross Heat Exchanger, and Kewanee Boiler—were combined into a single organization under a new name: American-Standard Industrial Division. The year 1959 was spent fruitfully—consolidating product lines, accelerating new product development, gearing up to meet the stepped-up requirements of the fast-paced, highly specialized power industry.



1960

Today, we're confident that you'll find new benefits in specifying products from American-Standard Industrial Division . . . products that now encompass the major fields of heat transfer, mechanical draft, boiler feed pump and fan control, fly ash and dust control, heating, ventilating, and air conditioning. The illustration at right shows where many of these products may be applied in a modern steam plant. Each is designed, engineered, and manufactured to help you produce power efficiently and economically. Each is backed by an honestly won reputation for reliability on the job.

Mechanical
Draft Fans

Dust c
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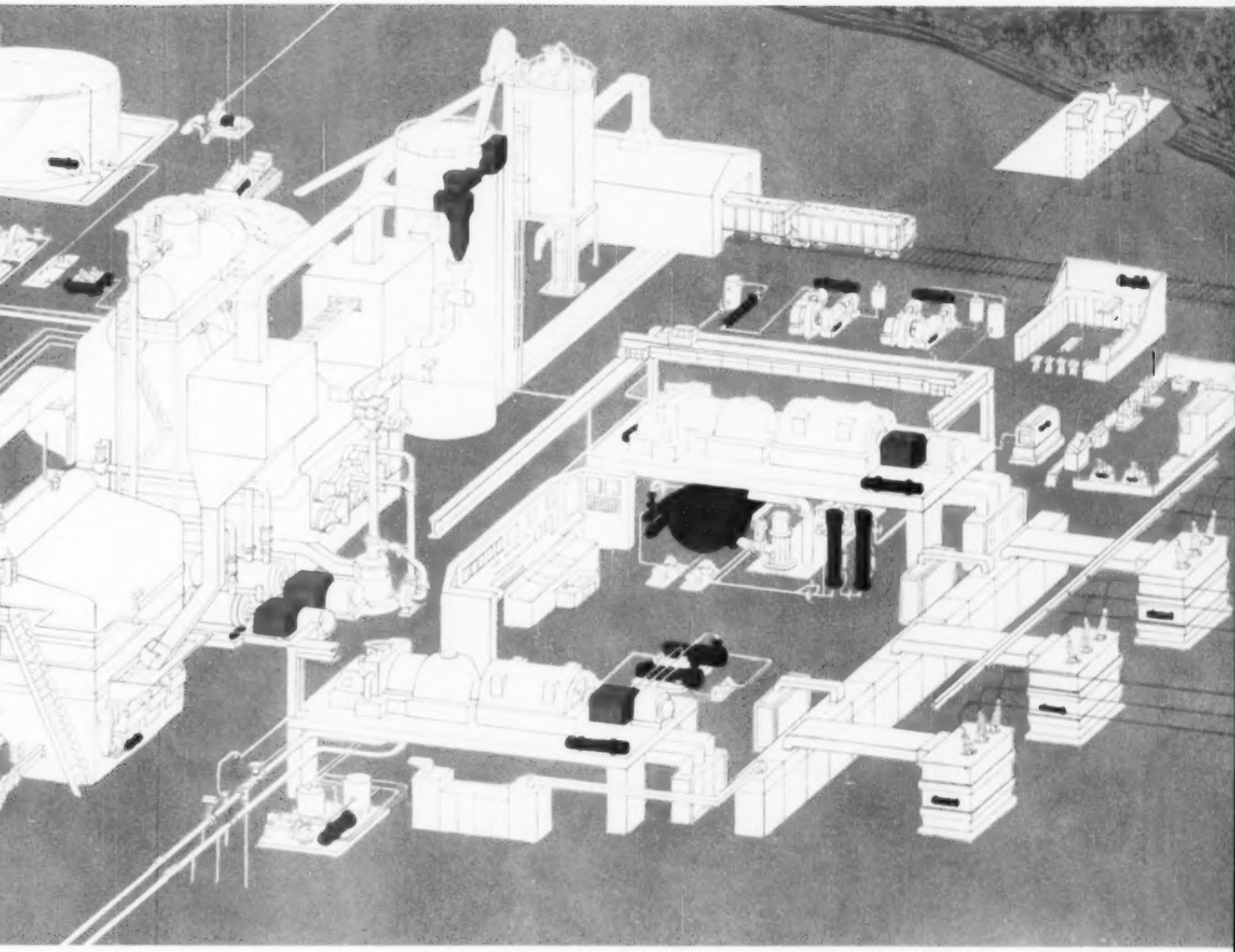
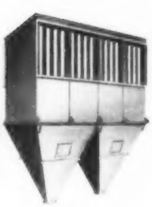
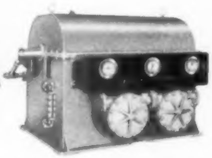


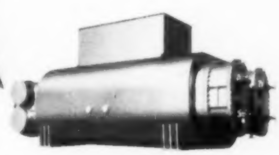
Here's where some of American-Standard Industrial Division products serve in a modern power plant.



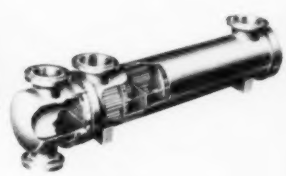
Dust and Fly Ash
Collectors



Gýrol® Fluid Drives for fan
and feed pump control



Surface Condensers
and Feedwater Heaters



Heat Exchangers
and After Coolers

By J. H. POTTER† and R. C. KING‡

The low-level economizer offers attractions as a means of removing additional energy from the flue gases downstream of the regenerative air heater. Performance of the low-level economizer, in combination with a water-to-air heat exchanger as an air-tempering device, is studied over a complete range of loads and ambient temperatures. At variable load, but at one fixed ambient temperature the low-level economizer performance when used as a main-cycle feedwater heater is studied. In both applications, for the specific 100-mw plant selected for study, the low-level economizer installation is justifiable from economic considerations.

Design Performance of the Low-Level Economizer*

THE process industries and the utilities have consistently sought means to improve plant economy and efficiency. In a large measure this has been accomplished by fuller exploitation of the heat-recovery devices generally available, and considerable thought has been given to the thermal and economic aspects of energy recovery.[1, 2]

Over the years the steam power cycle has shown improvements in heat rate due to the elevation of initial pressures and temperatures, the adoption of reheat, the extension of the regenerative cycle to include a larger number of feedwater heaters, and a general reduction of the losses in the turbine and generator and in the station auxiliaries. In one recent plant[3] a portion of the feedwater heating is done in a low-level economizer, utilizing energy in the stack gases that would otherwise have been wasted.

In this paper the possible improvement in economy resulting from a recovery of a larger portion of the flue-gas energy is investigated. Paramount in this study is the realization that the energy which is recovered from stack gases must be returned to the cycle. No gain would result from a reduction in stack temperature, for example, by exchanging heat with the atmosphere alone. Several schemes for the utilization of recovered energy are possible, among them being:

1. A transfer of heat, either direct or indirect, from the hot flue gases to the combustion air.
2. A transfer of heat from hot flue gases to the feedwater of the main power cycle.
3. A combination of the foregoing.
4. A system in which gases would be scrubbed by water. The energy recovered would be transferred to the main-cycle feedwater system, to protect the air heater

* Presented at the Annual Meeting, American Society of Mechanical Engineers. Nov. 29–Dec. 4, 1959, Atlantic City, N. J., as ASME Paper No. 59-A-222.

† Stevens Institute of Technology.
‡ Gibbs and Hill, Inc.

[1] "The Utilization of Waste Heat," by J. H. Potter, *Mechanical Engineering*, vol. 81, 1959, pp. 54–58.

[2] "Regenerative & Recuperative Devices for Industrial Gas-Burning Equipment," by J. H. Potter and K. H. Weil, American Gas Association, 1958.

[3] "Eddystone Supercritical Heat Cycle Incorporates Stack Gas Heat," by S. M. Arnow, COMBUSTION, vol. 21, April 1957, pp. 34–38.

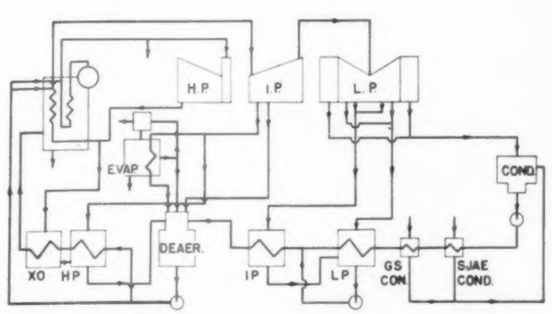


Fig. 1—Basic station cycle

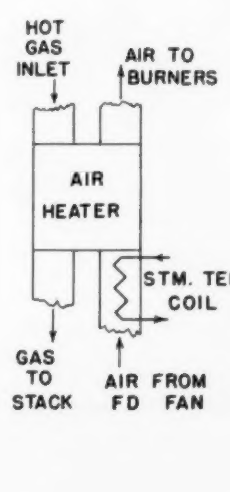


Fig. 2—Location of the steam-tempering coil

by tempering and to reduce the dust content in the stack effluent.

5. A system that would exchange heat from the hot gases to the feedwater system, but which would operate at condensation temperatures so as to recover water vapor from the products of combustion.

An existing 100,000-kw installation was selected as the basis for the present study. The plant is installed at an altitude 5000 ft above sea level and the steam-generating unit is arranged to burn coal, oil, or natural gas. The cycle as shown schematically in Fig. 1, consists of a steam-generating unit, turbine-generator unit, two low-pressure feedwater heaters, a deaerator, two high-pressure feedwater heaters, an evaporator, and the usual complement of auxiliaries. The boiler is of the radiant type; the superheater is part radiant and part convective; the reheater and main economizer are located in the convection zone. Steam temperature control is by injection of desuper-heat water and by gas recirculation. A regenerative air heater is installed. Throttle pressure and temperature are 1450 psig, 1000 F, respectively, with reheat to 1000 F. Two low-level economizer applications, air tempering and feedwater heating, were selected for study. Heat-balance diagrams for 110,000 kw (maximum expected throttle flow), 75,000 kw, 50,000 kw, and 25,000 kw were available for the actual plant design. These balances were used in the study and were designated arbitrarily as 4/4, 3/4, 2/4, and 1/4 load, respectively. All calculations involving air and gas quantities and temperatures were based on a midwest coal having the following proximate analysis.

	Per Cent
Moisture	13
Volatile matter	35.2
Fixed carbon	39.6
Ash	12.2

The sulfur content was 4.39 per cent and the higher heating value was 11,200 Btu per pound.

It is well known that, in order to prevent excessive corrosion of the regenerative air heater, it is necessary to provide a so-called minimum cold-end temperature. This temperature is the arithmetic average of the temperatures of the entering air and leaving gas, uncorrected for air leakage. For the coal selected for this installation, the manufacturer recommended a cold-end temperature of 210 F.

Tempering of Combustion Air

In the conventional arrangement, this minimum requirement is met by the installation of a tempering coil in the air stream ahead of the regenerative heater as in Fig. 2. The tempering coil is heated either by the steam that is extracted from the turbine cycle, or by the condensate that has passed through one of the main-cycle feedwater heaters. It is not the intent here to discuss the relative merits of the two schemes; on the contrary, the tempering scheme utilizing steam extracted from the turbine has been selected arbitrarily as the one with which the low-level economizer installation is compared.

Fig. 3 shows the air-tempering arrangement with the low-level economizer. Flue gases pass over the finned economizer surface and heat is transferred to a liquid loop. The hot liquid then passes through the air-tempering coil where it gives up a portion of its energy to the entering air. Cool liquid leaving the tempering coil is returned by a pump through the low-level economizer. The liquid contained in the closed-loop system may be water or, for outdoor installations, may be a non-freezing mixture such as water and ethylene glycol. In the present study, the fluid has been assumed to be water with a constant specific heat of unity. The economizer has been located downstream of the dust collector and induced draft fan so as to reduce to a minimum the deleterious effect of possible corrosion, and to recover the energy added by the induced-draft fan. The selected location is purely arbitrary; had the economizer been located immediately downstream of the air heater, there would have been a decrease in draft loss through the dust collector and flues, a possible reduction in dust collector investment, and an increase in stack gas temperature.

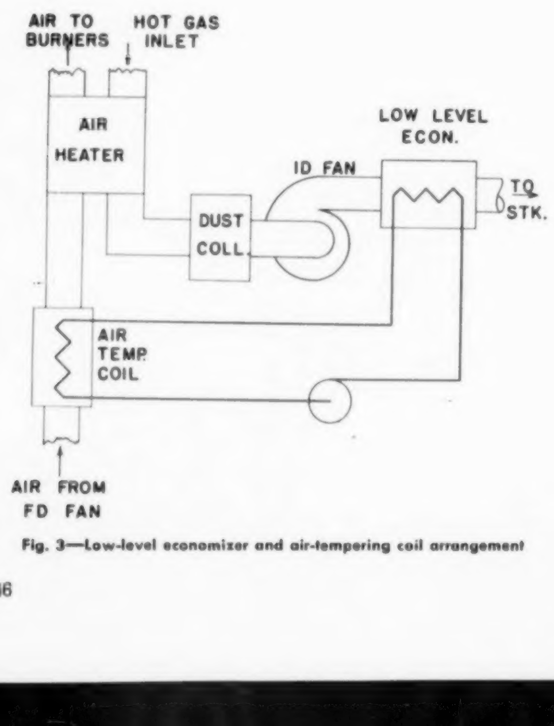


Fig. 3—Low-level economizer and air-tempering coil arrangement

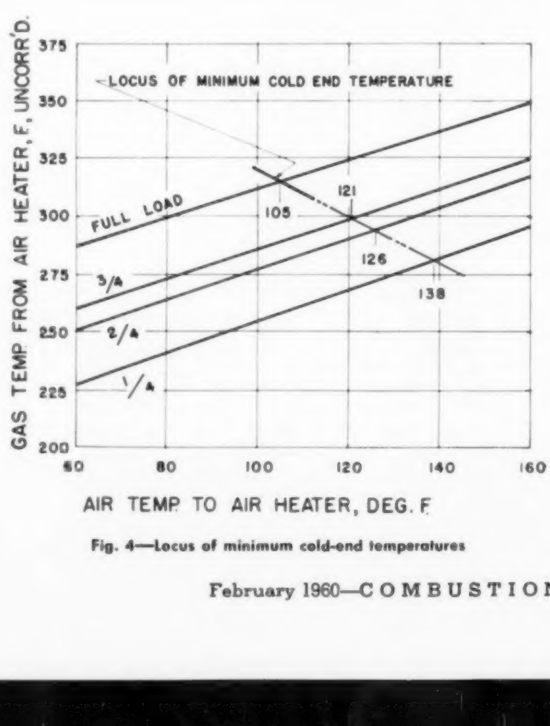


Fig. 4—Locus of minimum cold-end temperatures

TABLE I—BASIC AIR AND GAS DATA

	Air Leaving Heater		Gas Entering Heater	
Load	Lb/Hr	Temp., F	Lb/Hr	Temp., F
4/4	865,000	568	1,056,000	677
3/4	620,000	543	765,000	630
2/4	491,000	538	615,000	612
1/4	320,000	534	390,000	595

For outputs ranging from full to one-quarter plant load, the gas temperature (uncorrected for leakage) at exit of the regenerative air heater is shown in Fig. 4 as a function of the air temperature entering the heater. Also plotted is the locus of 210 F minimum cold-end temperature. It is observed that, at full load, an air temperature of 105 F is required at entrance to the regenerative heater, while at one-quarter load, an air temperature of 138 F is required.

For purposes of steam-tempering coil selection, the source of steam supply was taken as the deaerator steam extraction line. Performance is shown in Fig. 5, A through D. It is noted that, at full load, a two-row coil gives protection to an ambient of minus 10 F, but that, at one-quarter load, the same coil would give protection only to 43 F ambient. A three-row coil was used in the calculation: with this selection, protection is provided to the desired minus 20 F ambient condition.

In all cases, condensate from the steam-tempering coils is returned to the main plant condenser. The total installed cost of the steam-tempering coils including all piping, traps and control valves would be about $25,000.

Heat-balance diagrams, without air tempering for full, three-quarter, one-half, and one-quarter loads were available for the basic plant cycle. Then, maintaining the four throttle flows, but extracting steam from the deaerator bleed point as necessary for steam-coil air tempering, the gross electrical generation at each of the four throttle flows was determined. Differential FD and ID fan power requirements caused by the presence of the tempering coil and economizer were calculated by first

TABLE II—INSTALLED COST OF ECONOMIZER INSTALLATION

Basic Economizer, complete with Washing System	$ 84,000
Air Tempering Coils	15,000
Circulating Water Pumps, Motors and Switchgear	2,500
Supplementary Steam-to-Water Heat Exchangers	2,500
Erection of Economizer, Air Tempering Coils, Suppl. Heat Exchanger	15,000
Wash Water Supply and Disposal Piping	6,000
Steam Supply Piping to Supplementary Heat Exchangers	2,000
Neutralizing Basin or Other Special Facilities	10,000
Control Valves and Wiring, Installed	2,000
Foundations and Structural Supports	5,000
Corrosion-Resistant Breeching, Installed	5,000
Plastic Coating of Stack Interior	16,000
Increased Cost of I.D. and F.D. Fans and Motors	5,000
	$175,000

determining differential friction drops at various ambient temperatures and then converting to horsepower on the basis of manufacturer's fan performance curves. Fig. 6 from the full-load condition, is typical of this calculation. It was assumed that all other auxiliary powers remained constant. Then the net generation at each of the four throttle flows was obtained by difference.

In determining the energy that had to be supplied in the form of fuel, the boiler manufacturer's guaranteed efficiency at the respective throttle flow was used. Due recognition was given to the higher combustion-air temperature that resulted from operation of the steam tempering coils. On this basis, the heat rate at each approximate load point was calculated.

The air and gas quantities and temperatures, as specified by the boiler manufacturer, for each load condition are shown in Table I. The steam-generating unit furnace operates under a slight suction and steam temperature control is partly by gas recirculation.

The low-level economizer was selected to match the regenerative air heater furnished as a part of the steam-generating unit. That is, no attempt was made to select the most economical combination of low-level economizer and air heater. A larger and more expensive economizer would permit the use of a smaller

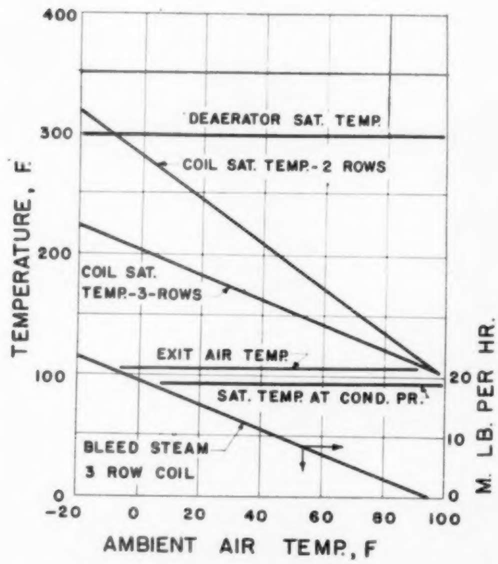


Fig. 5(a)—Steam-tempering-coil performance—full load

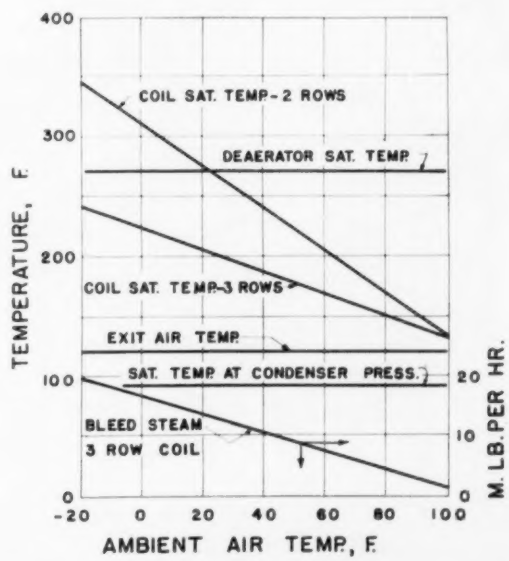


Fig. 5(b)—Steam-tempering-coil performance—three-quarter load

and less expensive air heater. The optimization of these two pieces of equipment was considered to be beyond the scope of this present paper.

The low-level economizer selected is of all cast-iron construction. It would be provided in two separate units of 240 tubes each, arranged 10 tubes high, 12 tubes deep and 2 tubes wide. The overall dimensions of each of the two units would be 6 ft, $2^3/_4$ in. high by 23 ft wide by 8 ft, 1 in. deep; operating weight would be about 167,000 lb for each unit. Estimated erection time is 1975 man-hours. The cost of the complete installation, as shown in Table II, is estimated at $175,000; it is pointed out that, in this estimate, provision has been included for special treatment of the flue, breeching and stack, all of which are subject to contact with low-temperature flue gas. Actual operating experience over a number of years may indicate that such special treatment is unnecessary.

For throttle flow and gross electrical generation corresponding to these four basic cycle loads, the differential forced-draft and induced-draft fan powers were calculated. Allowance was made for differential friction due to different air and gas temperatures at the various ambients through equipment and through ducts, flues, and the stack. In determining the differential I.D. fan power, due regard was given to the variation in stack theoretical draft owing to difference in both gas and ambient air temperatures. In these calculations, a resistance at each load equal to twice the "clean" value as calculated by the manufacturer was assumed through the economizer. Fig. 7 is an example of the results of the calculation for the full-load condition.

Assuming that there was no variation in auxiliary power other than that due to the differential FD and ID fan power, the net generation at each ambient was calculated. The required energy addition in the steam-generating unit was taken as that of the basic heat balance plus any required supplementary heat, and less the differential energy carried into the furnace as a result of higher combustion-air temperature.

The decrease in heat rates as a function of ambient air temperature is shown for all four loads in Fig. 8. An inspection of the curves reveals the following:

1. For all loads, the improvement in heat rate is greatest at low ambient temperatures. This is to be expected as the throttle flow at each load was maintained constant: the increased tempering steam requirements at low ambients represent a greater fraction of the throttle flow than at high ambients.

2. Over practically the entire range of ambient air temperatures, the decrease in heat rate is greater at low loads than at high loads. This is attributed to two factors: (1) As stated before, the throttle flow was arbitrarily maintained at a constant value; (2) frictional resistance through the extra equipment has a much smaller effect at low than at high loads.

3. At very low ambients, the necessity of supplying supplementary heat for maintenance of minimum cold-end air heater temperature may cause a reduction in the rate at which the heat rate decreases. That is, the curves may indicate a maximum saving in heat rate.

Pertinent performance characteristics of the economizer and tempering coil installation are shown graphically in Fig. 9 (a) through (d). Two basic requirements must be satisfied by the installed equipment: (1) The air heater must be protected by means of supplying air at a sufficiently high temperature to match the minimum cold-end requirement; (2) the economizer must be supplied with water at a sufficiently high temperature so that the base of the extended surface will be safely above the water dewpoint. The air heater manufacturer specified 210 F as the minimum cold-end temperature; the economizer manufacturer specified 100 F as the minimum water temperature at economizer inlet.

Reference to Fig. 9(a) shows that the uncontrolled economizer inlet water temperature is 100 F at 16 F ambient air temperature. Thus, at full load at 16 F ambient and below, it is necessary to institute some sort

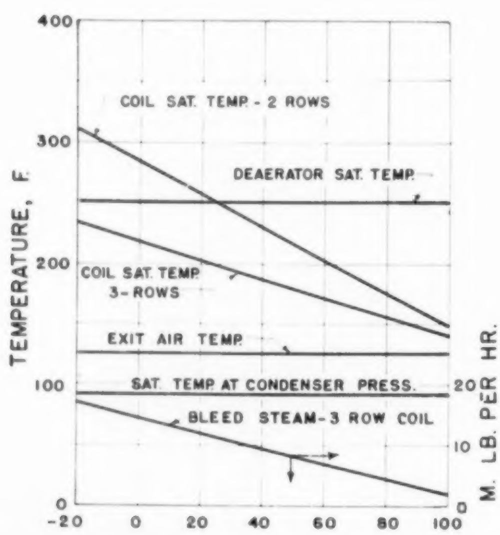


Fig. 5(c)—Steam-tempering-coil performance—half load

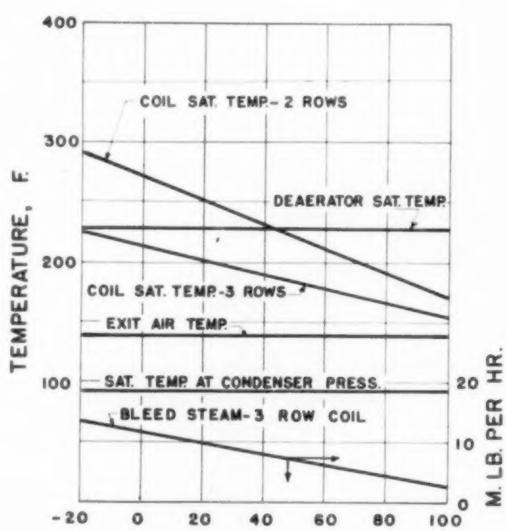


Fig. 5(d)—Steam-tempering-coil performance—one quarter load

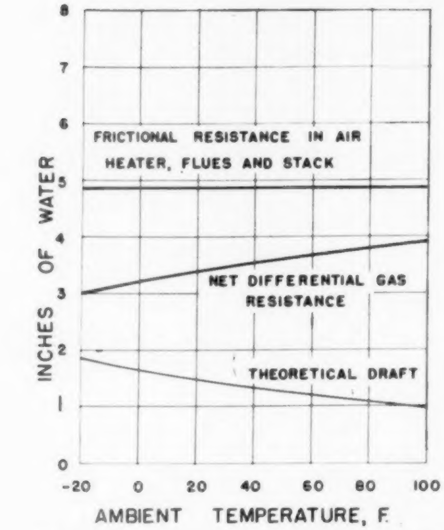


Fig. 6—Gas resistances—steam-tempering coil scheme

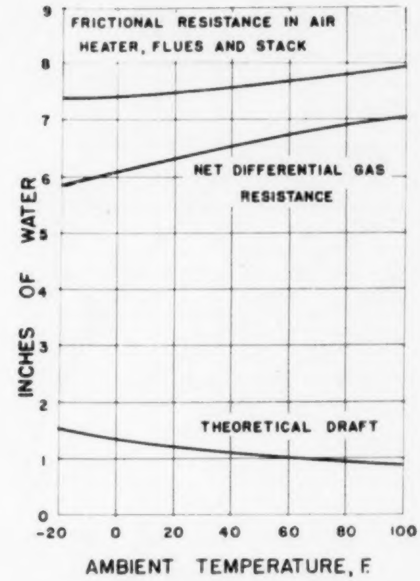


Fig. 7—Gas resistances—low-level-economizer scheme

of control for economizer protection: the control scheme shown in Fig. 10 was assumed.

This control scheme embodies two features—an automatic temperature-controlled by-pass valve and a supplementary steam heater. The by-pass valve opens automatically whenever economizer inlet water temperature reaches 100 F. The supplementary heater steam inlet valve opens whenever the arithmetic average of the regenerative heater air inlet and (uncorrected) gas outlet temperatures reaches 210 F.

Referring again to Fig. 9(a), it is seen that when by-passing commences, the slope of the "air entering air heater" curve increases. This is due to the fact that mass water flow through the air tempering coil is decreased; with a reduction in water flow, heat transfer to the air is decreased and, consequently, air enters the air heater at a lower temperature. The reduction in inlet air temperature results in a corresponding decrease in both uncorrected and corrected gas temperatures. Thus, there is a sharp reduction in cold-end temperature. This reduction continues at a constant rate until, at minus 8 F ambient, the minimum 210 F cold-end temperature is reached, the steam inlet valve at the supplementary heater is automatically opened, and all temperatures remain constant thereafter.

Referring now to Fig. 9(b), it is observed that by-passing begins at 6 F ambient, and that supplementary heating is required at ambient temperatures below minus 2 F, with by-passing being required over a range of only 8 degrees.

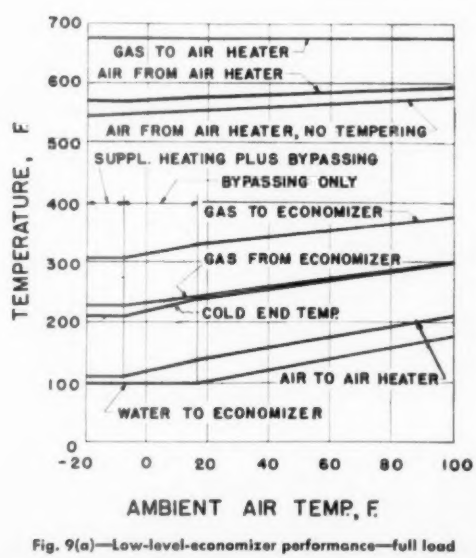


Fig. 9(a)—Low-level-economizer performance—full load

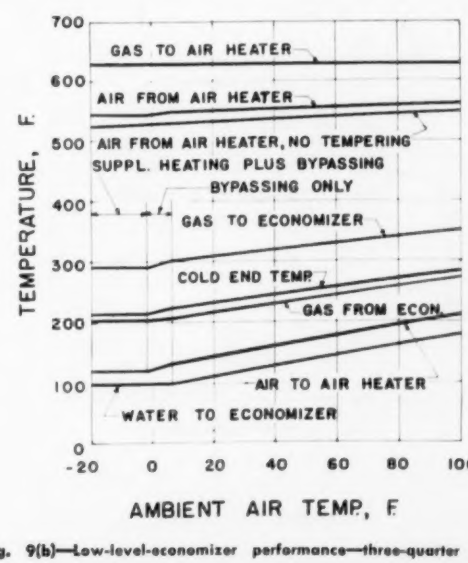


Fig. 9(b)—Low-level-economizer performance—three-quarter load

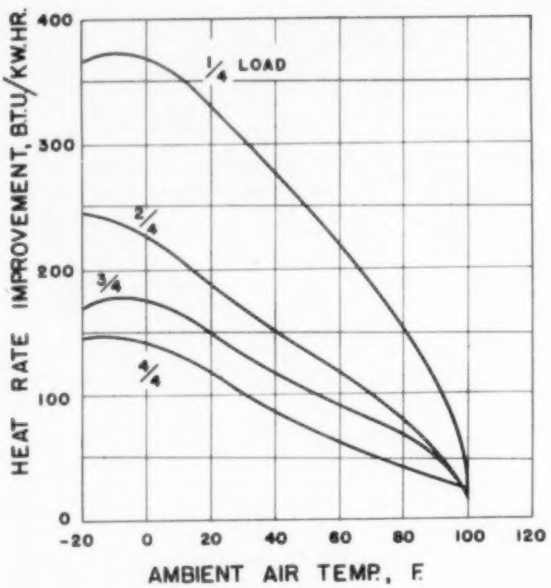


Fig. 8—Heat-rate improvement—low-level-economizer versus steam tempering

At half load, Fig. 9(c) indicates that by-passing begins at minus 3 F and that supplementary heating is required at ambient temperatures below minus 6 F. That, is by-passing is required over a range of only 3 F.

At one-quarter load, as shown in Fig. 9(d), the minimum cold-end temperature is reached at 10 F; the economizer water inlet temperature at that time is 112 F and the by-pass valve is therefore closed. Steam is admitted to the supplementary heater for air heater protection and all performance characteristics, except the economizer water inlet temperature, remain constant.

Table III shows the supplementary heating requirements. It was assumed that this steam would be supplied at reduced pressure from the steam drum of the boiler.

TABLE III—SUPPLEMENTARY HEAT REQUIREMENTS, MILLION OF BTU PER HR

	Ambient Temperature	
Load	−20 F	0° F
4/4	2.70	0
3/4	2.90	0
2/4	1.20	0
1/4	2.23	0.67

TABLE IV—FLOW THROUGH BY-PASS, LB/HR

	Ambient Temperature	
Load	−20 F	0° F
4/4	110,000	79,000
3/4	103,000	81,000
2/4	118,000	0
1/4	0	0

TABLE V—WATER TEMPERATURE EXIT OF TEMPERING COIL, DEG F

	Ambient Temperature	
Load	−20 F	0° F
4/4	43	68
3/4	57	74
2/4	63	102
1/4	103	108

Table IV shows the water quantities that must be by-passed for economizer protection. The required quantities are all of sufficient magnitude to ensure effective control.

At large heat-transfer duties in the tempering coil, there is the possibility that water leaving the tempering coils might be dangerously near the freezing point. For the cases studied, despite the large by-passed quantities, the lowest exit temperature reached was 43 F, as shown in Table V.

In addition to the savings in heat rate, for constant throttle flow, there is also considerable increase in net electrical generation due to the economizer installation. This increase in net output is greatest at low ambients which call for the greatest quantities of bled steam; at high ambients, the increase becomes smaller and, at very high ambients becomes negative due to two factors. First, the amount of bled steam required is smaller and,

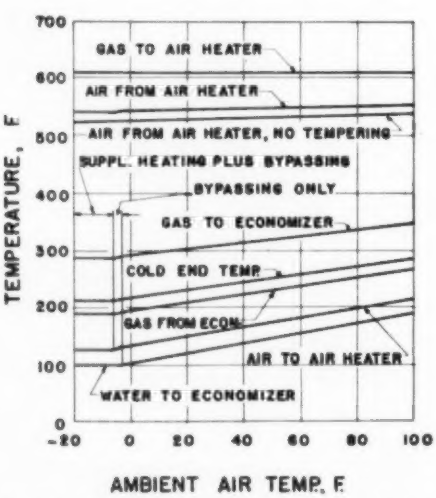


Fig. 9(c)—Low-level-economizer performance—half load

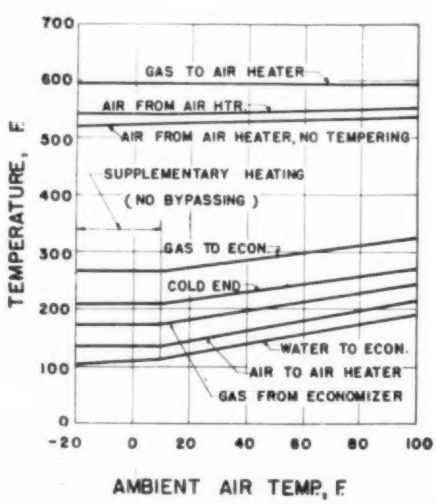


Fig. 9(d)—Low-level-economizer performance—one-quarter load

TABLE VI—INCREASE IN NET GENERATION FOR EQUAL THROTTLE FLOW (STEAM TEMPERING TAKEN AS BASE)

Ambient Temp., F	4/4	3/4	2/4	1/4
−20	1755	1400	1100	735
0	1380	1145	920	630
20	1035	900	730	515
40	690	670	560	410
60	350	450	390	315
80	60	225	220	205
100	−200	−100	−70	−30

TABLE VII—HOURS OPERATION PER YEAR

	Load on Station			
Ambient Temp., F	4/4	3/4	2/4	1/4
−20	40	20	10	10
0	160	80	40	40
20	700	300	150	50
40	800	500	200	260
60	1500	1000	200	100
80	1200	440	200	200
100	200	100	160	100
	4600	2440	960	760

second, the increase in frictional resistance and decrease in theoretical stack draft more than offset the extra energy due to the higher temperature of the combustion air. The variation in net generation is shown in Table VI.

Any economic evaluation of the relative merits of steam tempering versus low-level economizer tempering must take into account the loading schedule of the station, the differential heat rates, the variations in net station output and, of course, the installed cost of equipment. In order to show some tangible results, the loadind schedule shown in Table VII was assumed. The distribution is entirely arbitrary.

With the loading schedule of Table VII and the differential heat rate curves of Fig. 8, the saving in the form of fuel is calculated as approximately 61 billion Btu per year. If a fuel cost of 40 cents per million Btu is assumed, the annual fuel saving would amount to $24,600. If this be amortized at, say, 15 per cent the present worth of fuel savings would be $164,000.

The average annual ambient temperature obtained by integration of Table VII is approximately 50 F. At this ambient, the full-load capability increase is approximately 500 kw. If that figure is assumed to be representative of the increased plant capability, and if capability were valued at $150 per kilowatt, the worth of the economizer increased capability would be $75,000.

The economics of the installation are summarized as follows:

Present worth of fuel saving	$164,000
Value of capability	75,000
Total	$239,000
Total cost of installation (differential)	150,000
Difference in favor of economizer	$ 89,000
Return on extra investment	59 per cent

It therefore appears that, for the conditions assumed in this study, there is an economic advantage in the economizer installation. However, it is again emphasized that there are available only meager data for central station plants operating at stack temperatures as low as those pertinent to this study. It may be that experience will indicate the necessity of greater expenditures in initial investment as well as an increase in outage time. Speculation on these items is deemed to be beyond the scope of this study.

Further, in an analysis of these results, it is again emphasized that all heat-balance studies were made at constant throttle flow. For all loads except that at maximum expected throttle flow, it obviously would have been possible to maintain the desired generation by a relatively small increase in throttle flow. Insufficient computational facilities were available to permit this approach; the industry can well benefit from further studies in that direction.

Low-Level Economizer as a Feedwater Heater

A second study was made in which a low-level economizer was substituted for the intermediate-pressure feedwater heater. The cycle is shown schematically in Fig. 11.

The low-level economizer was selected on the basis of matching the feedwater quantity at full load, at an ambient air temperature of 80 F. There was a small increase in the quantity of steam bled to the deaerator at full load.

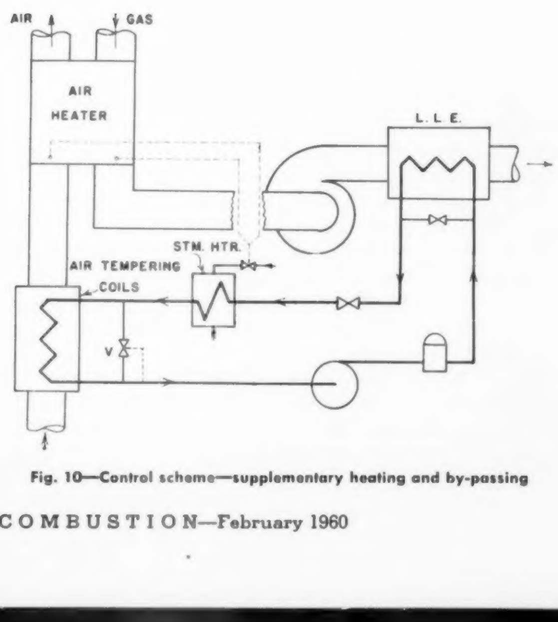


Fig. 10—Control scheme—supplementary heating and by-passing

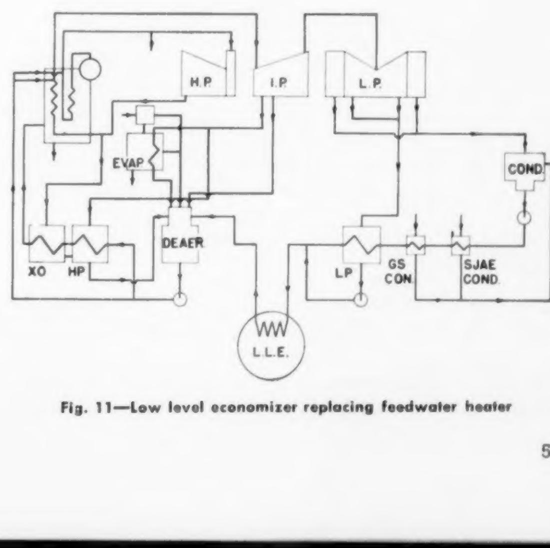


Fig. 11—Low level economizer replacing feedwater heater

TABLE VIII—HEAT RATE COMPARISON FOR $1^1/_2$-IN. HG ABSOLUTE BACKPRESSURE AT AN AMBIENT AIR TEMPERATURE OF 80 F

Load	Conventional Cycle, BTU/kwhr	Low-Level Economizer Cycle, BTU/kwhr	Reduction, BTU/kwhr
4/4	10,258	10,154	104
3/4	10,439	10,315	124
2/4	11,210	11,024	186
1/4	13,704	13,336	368

For each of the four load conditions, the heat balance was recalculated. In the computations it was assumed that the extra generation corresponding to the steam quantity saved by not extracting for the intermediate-pressure feedwater heater could be realized. Full account was taken of variation in extraction pressures and evaporator vapor quantities. The decrease in theoretical draft was considered as well as the variation in induced draft fan power occasioned by the resistance of the low-level economizer. The boiler feed pump work was corrected for variation in feedwater quantity. The results of the heat-balance modifications are summarized in Table VIII, extraction for steam tempering coils having been provided in all cases.

It will be observed that the improvement in heat rate is greater at light loads than at heavy loads. This is due primarily to the fact that the steam which would have otherwise been extracted for feedwater heating became available for producing more electrical output.

At all loads except full load, the energy available due to heat transfer was so great that sizable reductions in extraction flow quantities were found. At one-quarter load, heat transfer in the economizer was so great as to permit by-passing of the high pressure heater.

The low-level economizer selected for this service is made of cast iron, with integral fins. The installation would comprise two units of 1380 tubes each to be fitted into a space 17 ft high by 10 ft deep by 23 ft wide. The operating weight of the economizer would be 926,000 lb, and would afford a heating surface of 100,300 sq ft. The estimated erection time would be 4710 man-hours. The cost of the complete installation is estimated at $300,000, as shown in Table IX.

If an hourly loading schedule similar to that shown in Table VII is assumed, the annual energy saving, as fuel, amounts to more than 86 billion Btu. At 40 cents per million Btu, this amounts to a saving of about $34,500. Amortized at 15 per cent, this is equivalent to a present worth of $230,000.

At each load there is an increase in capability due to the fact that more steam is expanded to condenser conditions. At full load this increase in capability amounts to 905 kw. The low-level economizer, complete with foundations, washing system, additional induced-draft fan and motor capacity and miscellaneous piping could be installed for about $300,000. The intermediate-pressure feedwater heater, which is to be replaced by the low-level economizer, would be worth about $25,000 installed.

The economics of the replacement are thus shown to be:

Present worth of fuel saving	$230,000
Capability increase at $150/kw	135,750
Total	$365,750
Net cost of economizer	$275,000
Return on extra investment	33%

TABLE IX—INSTALLED COST OF LOW-LEVEL ECONOMIZER TO REPLACE INTERMEDIATE-PRESSURE FEEDWATER HEATER

Basic Economizer complete with Washing System	$211,700
Erection of Economizer	23,000
Piping in Feedwater Circuit	7,500
Extra I.D. Fan and Motor Capacity	7,000
Foundations and Structural Changes	12,000
Wash Water Supply and Disposal System Piping	4,800
Neutralizing Basin or Other Special Facilities	13,000
Corrosion-Resistant Breeching Installed	5,000
Plastic Coating of Stack Interior	16,000
Total	$300,000

Time did not permit an investigation of the replacement of the intermediate-pressure feedwater heater by a low-level economizer over a wide range of ambient temperatures. It is to be expected that poorer heat rates will be encountered as the ambient air temperature decreases, regardless of the method of feedwater heating.

As has been pointed out, the investigation compared a cycle involving a low-level economizer used for feedwater heating with one containing a conventional extraction-steam feedwater heater: in both cases, a high-sulfur fuel requiring some form of air tempering was assumed. If a fuel was used which did not require air tempering, the gas weights involved would dictate a different economizer surface. In such a case, the heat-rate reductions would certainly be different and, the authors suggest, somewhat lower than those obtained for the case studied.

Discussion

The low-level economizer holds considerable potential as a device for recovering thermal energy that might otherwise have been wasted. How that energy is utilized is of prime importance; the low-level economizer must therefore be judged in terms of the effect it will produce in the overall system.

Throughout this analysis, it has been assumed that the flues downstream of the economizer, the stack breeching, and the stack are capable of withstanding the deleterious effects of corrosion. To the best of the authors' knowledge, insufficient data are available on installations of size and duty comparable to the station selected for study. Only time will tell whether or not operating difficulties due to low exit temperatures will result from recovery of a larger portion of the flue gas energy.

As operating experience is gained, still further economies may be effected by installation of the low-level economizer adjacent to the air heater. In that location, the dust collector may be reduced in size and cost; further, the induced draft fan will be required to handle a lower volume rate of flow of gas with an accompanying saving in power consumption.

In the case in which a low-level economizer was used in lieu of a conventional extraction-steam feedwater heater, it was pointed out that poorer heat rates would be expected with a decrease in ambient air temperatures. In the case in which a low-level economizer and water-to-air, heat-exchange coils were used in lieu of steam-tempering coils, it was shown, Fig. 8, that better heat rates are to be expected with a decrease in ambient air temperatures. This circumstance indicates that there may be considerable advantage in an installation which would be arranged to provide for both feedwater heating and for air tempering; at low ambients, most of the

energy transferred from the hot gases in the low-level economizer would be used for air tempering, whereas, at high ambients, the principal use of the low-level economizer would be for feedwater heating. Such an arrangement would, of course, require more extensive apparatus and may not be justifiable from an economic point of view. The industry could well benefit from investigations in this direction.

Conclusions

For the particular cycle investigation in this study:

(1) As a replacement for conventional steam-tempering coils, the low-level economizer shows greatest promise at low ambient temperatures and at part-load operation. When the ambient temperature approaches that corresponding to the air heater cold-end temperature requirement, the value of the economizer decreases.

(2) As a replacement for the intermediate-pressure feedwater heater, the low-level economizer shows significant potential savings in both operating cost and in increased capability of the turbine. The contribution of the economizer is greater at higher ambient temperatures.

Fuels at The 1959 ASME Annual Meeting

A two paper session on basic fuels contrasted the American and European fuels and their influence upon the design of boiler units under development in their areas.

A. F. Duzy, Babcock and Wilcox Co., opened the session with his paper "American Coal Characteristics and Their Effects on the Design of Steam Generating Units." Manufacturers of coal-burning steam-generating equipment, Mr. Duzy stated, must keep abreast of all methods of evaluating coal characteristics. Since all coal contains ash, the designer of high-pressure, high-temperature steam generators must have a thorough knowledge of ash characteristics and their effect on fouling, slagging, erosion and corrosion of boiler surfaces. It is also desirable to initiate, by research, new methods of evaluation so that improved steam generators may be offered.

The designer of fuel equipment and boilers requires simple, reproducible, dependable laboratory tests and analyses of coals to predict their behavior.

Important coal characteristics to be considered are the percentage by weight of moisture, volatile matter and ash, which are obtained from the proximate analyses, the calorific value, ash-fusion temperatures and composition, sulfur content, size distribution and grindability. The ultimate analysis is used to determine accurately the theorectical air requirements for combustion. If an ultimate analysis of a coal is not available, approximate air requirements per 10,000 Btu may be determined from the volatile-matter content. Actual theoretical air requirements of coal determined from the combustible constituents of coal may vary from about 7.3 to 8.2 lb per 10,000 Btu.

Another important characteristic of coal is its flowability, or ease of handling, which is dependent upon its moisture content, size distribution and, in some cases, its temperature and impurities, such as clay. The agglomerating index is important insofar as coal rank is concerned. Other characteristics of coal, such as plasticity and swelling, are not considered important.

For stoker-fired boilers size consist, moisture content, volatile-matter content, calorific value, ash content and ash-fusion temperature of the coal are to be considered.

Moisture content, size distribution and, to a lesser extent, sulfur and abrasiveness are coal characteristics which affect the design of downspouts, scales and feeders.

Size consist and bulk density of coal are important when excessive fine coal and moisture variation may cause either flooding or stoppage of coal flow. Sulfur content of coal may become important when it exceeds 4 per cent. Stainless-steel downspouts are recommended. Coal-feeder wears liners are made of stainless steel regardless of the sulfur content of the coal.

Grindability of coal is a poor indication of abrasiveness and should not be considered as a reliable indicator of wear. There is a definite need for an abrasiveness index of coal. Research is presently being performed to establish such an index which may be used to predict wear of feeding equipment, crusher elements and pulverizer grinding elements. Exploratory tests indicate that pyritic sulfur, moisture and ash contents play an important role in determining abrasive properties of coal.

P. Pracht, H. Hennecke and **G. Redottee,** of the Babcock and Wilcox-Dampfkessel Werke AG, Western Germany, handled as their subject "The Combustion of European Coals in Modern German Steam Generators." The European fuels being fired in modern steam boilers differ from American fuels known by an average higher content of ballast and a lower portion of volatile. Moreover the occurrence of coal workable according to American ideas is insufficient for the European energy requirements, so there are fuels mined of rather low-grade. These low-grade fuels are treated by washing to obtain salable fuels and by-product residues comparatively hard to sell, so-called middlings. To increase the profitability of the mines, the middlings are burned in steam power stations especially erected in these mines.

Every consideration, in the opinion of the speakers, needs be given to the planning of the raw-coal bunker for a continuous coal discharge from the bunker. Especially in case of fuels of high moisture content the correct design of the raw-coal bunkers if of importance to avoid bridge formation.

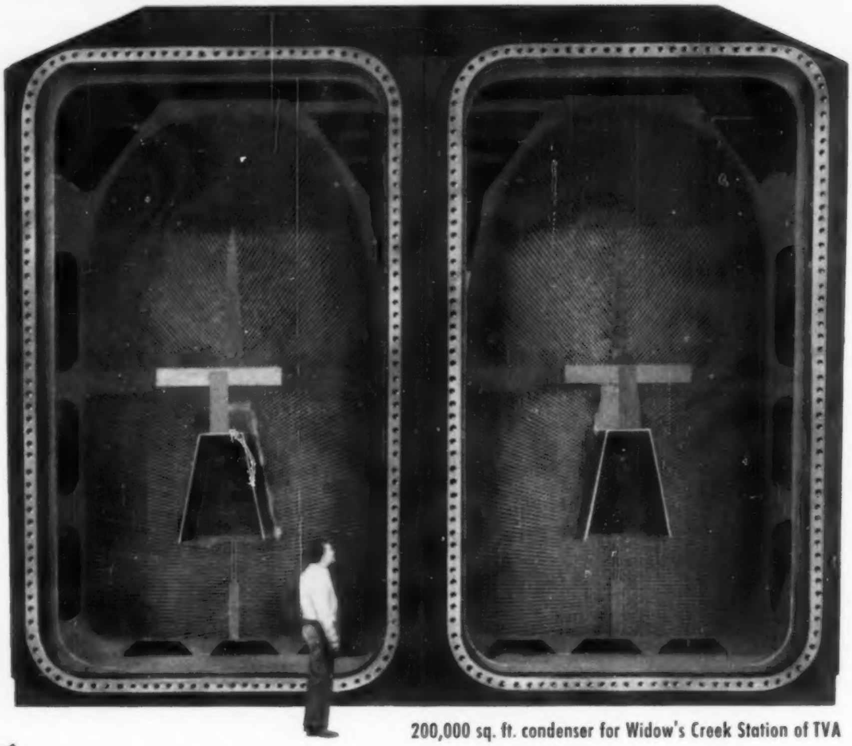
The following experience has been gained as regards the design of raw-coal bunkers:

(*a*) The bunker discharge shall be neither square nor round, but rectangular. The smallest dimension shall be 800 mm. The slot-shaped design is most advisable.

(*b*) A vertical bunker wall is recommended. The walls being not truly vertical but have inclinations from 65–75 deg. Opposite walls shall have different inclinations.

(*c*) The bunker walls must be smooth. In special cases plastic coating must be used.

3 STORIES HIGH



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The Boiler Efficiency Dilemma—Or the Fight to Lower Exit Gas Temperature

by GEO. W. SWITZER

Gilbert Associates, Inc.

BOILERS in steam power plants have reached a high efficiency level. Each step in the advance has been a struggle up the ever-steepening hill of diminishing returns. In the past few years, the struggle to make justifiable improvements in boiler efficiency has grown more difficult since fuel prices have not increased significantly. Among the measures taken to attain the best possible boiler efficiency is the lowering of temperature of the flue gases to the stack. Since the heat loss to the stack on the conventional utility boiler is about 8 per cent of the heat in the fuel, this appears to be the most fruitful field for further gains in boiler efficiency.

Reducing Flue Gas Temperature

Reduction of flue gas temperature by the use of larger air heaters will show lower flue gas heat loss and consequently better boiler efficiency. However, reduction of flue gas temperature leaving the air heater inevitably runs "smack dab" into the necessity of maintaining safe metal temperatures in the air heater. The point is quickly reached where any further reduction of outlet gas temperature will require increased temperature of the air entering the air heater. It is usual for air heater size selections to require some artificial control of metal temperatures at low ambients and reduced load on the unit. However, some units have been installed in recent years which require artificial control of metal temperatures even at full load under summer ambient conditions.

The purpose of maintaining air heater metal temperature above some definite value is to avoid excessive condensation of vapor from the flue gas on the metal surfaces. This condensation if permitted would result in corrosion and in the case of gases containing solids, a build-up of deposits. The value of metal temperature which must be maintained to avoid excessive condensation depends broadly on the amount of sulfur in the fuel and specifically the amount of sulfur trioxide produced by the combustion. The amount of sulfur trioxide produced is a small but extremely potent constituent of the flue gas. It results in an acid dew point temperature of the flue gas considerably higher than the water dew point temperature. It is usual, for instance, in burning bituminous coal to have an acid dew point temperature around 285 F while the water vapor content of the flue gas would give a dew point temperature around 97 F. As flue gas temperature is reduced, the first condensation consists of 100 per cent strength sulfuric acid. As the flue gas temperature is reduced below the acid dew point the acid becomes successively more dilute until at the water dew point, the sulfuric acid strength becomes virtually zero. In practice, metal temperatures are not maintained above the acid dew point, experience having proved that metal temperatures somewhat below the acid dew point will operate satisfactorily as to corrosion and build-up. The actual minimum metal temperature which must be maintained on a given installation with a given fuel can only be determined by trial (including going too far). However, correlated empirical data enables the air heater manufacturer to make general recommendations based on the sulfur content and certain other data on the fuel.

Air Heater Sizing and Operation

From the foregoing it is seen that the fuel characteristics set a limit on the minimum metal temperature which can be employed in operation and hence on the economics of air heater sizing and operation. If relatively small air heaters are selected, the outlet flue gas temperature will be relatively high and the inlet air temperature can be correspondingly low without the metal temperature going below the required minimum. If, on the other hand, relatively large air heaters are selected to achieve low outlet flue gas temperature, the inlet air temperature cannot be allowed to also go low lest the metal temperature be below the required minimum. Besides the variation in ambient temperatures an additional factor entering into air heater minimum metal temperatures is the effect of reduction of load on the boiler. Reduction of load results in a reduction in outlet flue gas temperature and this also must be prevented or counterbalanced by an increase in inlet air temperature if the required minimum metal temperature is to be maintained.

There are three methods commonly used to provide control of air heater metal temperature. These commonly used methods compared in Table I are:

(1) Bypass a portion of the cold air from the air heater inlet to the air heater outlet.

(2) Recirculate hot air from the air heater outlet to the forced draft fan inlet or the air heater inlet.

(3) Preheat the air ahead of the air heater inlet with heat extracted from the turbine cycle.

THE QUALITATIVE EFFECTS OF AIR HEATER METAL CONTROL

	Cold Air Bypass	Hot Air Recirculation	Air Preheating
Inlet air temperature	Not affected	Increases	Increases
Outlet gas temperature	Increases	Decreases	Increases
Outlet air temperature	Decreases	Decreases	Increases
F. D. fan head	Decreases	Increases	Increases
F. D. fan volume	Not affected	Increases	Not affected

In effect, air bypass controls metal temperature by raising flue gas outlet temperature with constant inlet air temperature, hot air recirculation by raising inlet air temperature more than outlet gas temperature is reduced and air preheating by raising both inlet air and outlet gas temperature. Air bypass, then has an adverse effect on boiler efficiency but a favorable effect on forced draft power consumption. Hot air recirculation has a favorable effect on boiler efficiency, but an adverse effect on forced draft power consumption. Air preheating has a favorable effect on boiler efficiency since the heat rejected in the flue gas is not as much as the heat added to the air and an increase in fan power consumption by the resistance of the air preheater coil.

Cost of Preheating to Cycle Heat Rate

There is, in the case of air preheating, a basic question which should be considered in addition to boiler efficiency and forced draft fan power. "Where do we get this heat which we put into the combustion air, and at what cost to the cycle heat rate?" If this heat is obtained by extracting steam from the turbine blade path there will be a loss of gross power generated by the turbine for a given amount of steam to the throttle. This is an adverse effect on the cycle heat rate. Thus, when large air heaters are selected based only on the comparison of boiler efficiency (outlet gas temperature vs. inlet air temperature) and the incremental cost of the larger air heater, a serious error can be made. The value of the net power generation loss from steam extracted can easily be the largest net economic factor, particularly if both station cost and energy cost are included in the evaluation.

The characteristics of the turbine cycle and air preheating requirements are not conducive to simple operation and selection of steam air preheating arrangements. As load is reduced on the unit, the air temperature required to maintain metal temperature in the air heater increases due to the decrease in outlet gas temperature. Reduction of load on the unit, however, decreases the extraction stage pressure and temperature. The result of the two effects reduces the temperature difference and hence reduces the heat transfer capability of the steam coil. It is entirely possible that a coil sized for 100 per cent load at an assumed minimum ambient temperature will be found inadequate to maintain minimum air heater metal temperature at some reduced load. An alternative to a larger size coil would be connecting to multiple turbine extraction points. This solution has only the single drawback that human nature will cause it to be left opened to the higher pressure extraction connection and the power generation loss will then be greater than necessary. Sometimes the air preheating coil is deliberately selected small to fit a space problem, to hold down first cost, or to step up steam pressure to accomplish coil drainage. Whatever the reason, selection of a small coil results in extraction from a higher steam pressure in the turbine and greater power generation loss. It cannot be too strongly emphasized that extraction of steam from the turbine results in reduction of gross power generated and this loss, though hidden, can easily be appreciable. If this is to be the method of control of air heater metal temperatures, then the purchase of large air heaters for a paper figure of boiler efficiency becomes a double-barreled mistake.

The Search For Different Approaches

From the foregoing discussion the question naturally arises as to whether we haven't reached an impasse on justifiable means of improving boiler efficiency by flue gas temperature reduction. The answer is "yes" unless a new approach is made to air heater metal temperature control.

Two such new approaches have been initiated:

1. Recovery of heat from the flue gases to preheat air to the air preheater.
2. Depression of the acid dew point of the flue gases by additives such as dolomite, zinc, ammonia.

As regards the recovery of heat from the flue gases, the question naturally arises "How is this any different from what we do in the air heater and by what means can we expect to avoid the consequences of low metal temperature?" The difference is in the type of equipment available for the purpose. In the conventional air heater both tubular and regenerative, the gas flows through passages of relatively small area compared to their length. Access to apply effective cleaning methods is therefore poor. In addition, the selection list of materials suitable for the construction of conventional air heaters is limited. The apparatus used for "tail end" heat exchange, on the other hand, is designed to expose the outside of tubes to the gas stream thereby lending itself to application of effective cleaning or in-service flushing. The materials of construction can be almost any that can be made into tubular form.

Low Temperature Economizer

The low-temperature economizer should be sized for the lowest load and ambient conditions for which air heater metal temperature must be maintained. This will result in an excess of performance available whenever the load and ambient are not at the minimum. It is logical in this case to divert the excess of flue gas heat to the feedwater cycle. This has the same effect as avoidance of steam extraction for air preheating. Whenever flue gas heat is applied to the feedwater cycle, less steam will be extracted for feed heating and the steam kept in the blade path of the turbine will increase the gross power generated for the same throttle flow.

Eliminating Dew Point

Efforts to eliminate the acid dew point of the flue gases, if successful, would open a very wide door to improved boiler efficiency and would push back present

limits of air heater metal temperatures. If the dew point of flue gases were 100 to 150 F instead of 250 to 300 F, it would be possible to design for considerably lower flue gas temperatures without getting into the complications of air heater metal temperature control. The economics of boiler efficiency would then be simply the cost of air heater surface versus the boiler efficiency gain and the turbine cycle loss could be avoided. Experiments along these lines have been conducted by injecting into various points in the boiler many materials intended to depress the dew point by adsorption or neutralization of the SO_3 or H_2SO_4 therefrom. From the standpoint of effectiveness and possible economic use, the most promising material thus far reported is ammonia.

The injection of small amounts of ammonia into flue gas will neutralize the small amount of SO_3 in almost theoretical proportions. However, the products of the chemical reaction themselves forms an adherent deposit where in service washing is not feasible. Hence, the injection of ammonia ahead of conventional air heaters does not appear feasible. However, it is suggested that the use of ammonia ahead of economizers for "tail-end" heat recovery would be feasible since the deposits would lend themselves to removal by in-service flushing.

Besides air heater corrosion and plugging, another problem with low flue gas temperature becomes serious with coal fired boilers. This is the matter of flyash removal and handling. In some cases, it is necessary to maintain flue gas temperatures above the limits required by the air heater in order to get satisfactory flow of flyash from collector hoppers and in transport systems. It is known that SO_3 adsorbs onto flyash at a temperature slightly above the acid dew point of the flue gas. As flue gas temperature is cooled to and below the acid dew point, increased amounts of water vapor will be absorbed by the SO_3 on the flyash particles to form H_2SO_4. It is apparent that flue gas temperature reduction ahead of dust collectors will reach a practical limit unless the acid dew point is neutralized. Since this has not yet proved feasible ahead of air heaters, it appears that better boiler efficiency from the use of large air heaters alone faces both an operating and an economic limit. It does not seem that "tail-end economizers" necessarily face the same limits since neutralization of the acid dew point ahead of such apparatus should be practical.

In summary, it appears that we have available the means to make justifiable economic advance toward better boiler efficiency and to solve the problems which can be foreseen. Our best wishes to the forerunners.

Dust Collector Coverage At Annual Meeting of ASME

"The Use of Transparent Scale Models in the Design of Dust-Collector and Gas Duct Systems for Coal-Burning Electric Generating Stations" was present by **E. F. Wolf, H. L. Von Hohenleiten** and **M. G. Gordon,** Baltimore Gas and Electric Co. The cost of dust collectors commonly used in American power plants, with the associated fly-ash-handling equipment and the supporting structures, is about 3 to 5 per cent of the cost of the entire generating station. Even with such a large investment, the collection efficiency may be low if the flue-gas ducts leading to and from the dust collectors are not designed to produce good gas distribution. In spite of its importance, the dust-collector system contributes nothing toward improved plant efficiency, and therefore, its design must be subordinate to the design of the major components of the plant. It must be fitted into the space available. Therein lies the crux of the problem. In this paper scale-model techniques are discussed which have been found to be very useful aids in the design of economical and effective gasduct systems and in their coordination with the dust collector.

The authors' company has had very good experience in the use of scale models as an aid in the solution of a fairly wide range of design problems, such as the design of stack structures for good gas dissipation, coal chutes and bunkers to prevent clogging, the approach channels for condenser circulator pumps and erosion studies in discharge canals. It was decided, therefore, to apply the scale-model technique to the study of gas flow in the duct system and precipitators for the generating-station extension.

As a specific example, the model study of the flue-gas duct for the first unit of the Herbert A. Wagner Generating Station was discussed in some detail. Observations of the full-scale ducts and dust collectors under actual operating conditions have shown that good correlation exists between the model study and the prototype.

A second paper on the same field of interest "Application of Model Studies to Industrial Gas-Flow Systems" was offered by **C. L. Burton** and **R. E. Willison,** Research Cottrell, Inc. This paper presented correlation of gas-flow patterns between scale models and full-size systems for industrial electrostatic precipitators and flues. Flow patterns had been determined in both systems by direct observations and measured velocity profiles. Several instances were then given showing successful correlation as evaluated by various criteria. Industrial-flue studies, the authors believed, are simplified by the use of model techniques since flow patterns are usually the primary variable to be studied. These studies provide additional evidence that the scale model is an important technique in designing gas flow systems.

Harry J. White and **Walter A. Baxter, Jr.,** Research-Cottrell, Inc., in their paper "A Superior Collecting Plate for Electrostatic Precipitators" analyzed the basic importance of collecting-electrode design to overall precipitator performance. They then described a scientific program leading to the development of greatly improved collecting plates broadly applicable to a wide range of practical applications. Fundamental and practical performance criteria evaluated included electrical characteristics, aerodynamic properties, precipitation rate, wrapping requirements, weight and cost. The new plate was reported as having been successfully applied to fly ash, cement, powered catalyst, gypsum and alumina dust, paper-mill, oxygen converter, and open-hearth fume and other recovery problems.

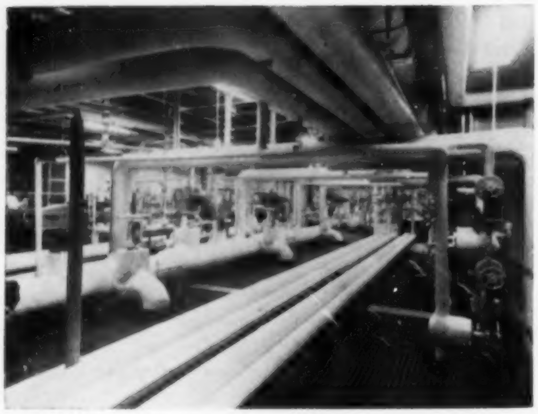

Fig. 1—Effective use of lighting shows in the above shot of a pipe gallery of the Sunbury Steam Electric Station

Fig. 2—A more difficult lighting problem is met in this view of the high bay lighting in Waterside Generating Station

Good Lighting Practice for Modern Power Plants

PETER W. SHERWOOD

Research Engineer*

Lighting of power plants much like ventilation is an ever present subject of concern to the efficient operation of a plant. Yet the economic consideration of cycle pressure, temperature, extraction points so dominates the thinking of the plant designer that an occasional pointed article such as the following is a helpful service.

ADEQUATE lighting is a key to improved manpower efficiency and safety in modern power plant operation. This recognition has led to the recent modernization of lighting arrangements in numerous generating stations.

In establishing adequate lighting conditions for power plants, the illuminating engineer must draw on two areas of information: a knowledge of general lighting requirements which are most conducive to efficient work performance, and a recognition of the lighting problems which are peculiar to a generation station.

General Lighting Requirements

Visibility of objects is influenced by five factors: size of the object time available for viewing, brightness, contrast, and glare. Of these, only the last three can be influenced by proper lighting design. Among these factors, contrast—i.e., the difference in light value existing between the object and its background—is least susceptible to influence. Significant contribution can be made, however, by the choice of light source and by its location relative to the object and viewer.

The needed level of brightness is a function of the object's size, the time available for viewing and, to some extent, the contrast in light values. Furthermore, the preferred level of brightness in a particular area is influenced by the accuracy of the required work and by the frequency with which it is carried out.

Objects can be discerned at very low levels of illumination. But under such conditions the actual seeing is unsatisfactory; work carried out is of low efficiency. As the light intensity is raised, neural and physical losses drop off very rapidly and the energy available for useful work increases at corresponding rate, until it reaches a maximum asymptotic value. Further increase in brightness beyond this point is without significant effect on human performance.

We are therefore dealing here with two opposing economic factors: the cost of illumination, which increases with rising brightness level, and cost of labor per unit of production or per unit of task performed, which decreases with brightness level until the asymptotic value of the brightness-efficiency curve is reached.

Since there are two opposing cost factors, which vary as different functions of the brightness level, we will find that there is an optimum economic level of light intensity to carry out any given task in industrial work. To determine this economic optimum with precision for a particular installation is not feasible since there are too many factors involved including the electric characteristics of the lighting system, the age of the lamps, and even the age of the human operator. However, lighting standards have become available for a great many industrial unit operations (among them, all situations which are normally encountered in power plants). These lighting standards are sufficiently close to the most favorable economic point to permit their adoption in any but very unusual circumstances which must stand on their own.

* White Plains, N. Y.

Selected Brightness Level

However, once a brightness level has been chosen, local factors must be considered to determine the best way in which the required intensity can be achieved. Here, two factors tend to be controlling: (1) economics of providing the brightness level by different types and (2) arrangements of luminaries and the degree of glare encountered with different such arrangements.

Glare is influenced by the nature of the objects to be viewed and their arrangement in the room relative to the light source. Glare is an abnormal pattern of brightness within the field of illumination which tends to cause annoyance, eye fatigue, interference with vision, etc., and thus will lead to decreased efficiency below the level attainable at the same brightness in the absence of glare. In general, glare may be largely removed by such expedients as mounting the lighting equipment as high as feasible, or by reducing the brightness derived from a single light source, using instead a large number of less powerful lamps.

Selection of luminaire, mounting height, and voltage to achieve a particular lighting effect in power plant practice must be subjected to economic analysis. Consideration must be given to both initial investment and annual operating costs, and the following check list covers the chief controlling factors in each category:

INITIAL COST:
- Net luminaire cost
- Cost of installation, including wiring
- Rate of depreciation (calculated as a percentage of the above two factors)

ANNUAL OPERATING COSTS:
- Number of burning hours
- Annual energy cost
- Rate and cost of lamp replacement
  - (a) Cost of lamp
  - (b) Cost of replacement labor
- Cost of cleaning lamps often enough to maintain adequate lighting standards (at least twice per year)
- Cost of electrical maintenance

TABLE I. SAMPLE POWER PLANT AREAS AND RECOMMENDED LIGHTING

Location	Recommended Illumination, Foot-Candles
Outdoor:	
Catwalks	2.0
Coal Unloading Dock	5.0
Car Dumpers	5.0
Coal Storage Area	1.0
Conveyors	2.0
Fuel Oil Delivery Heads	5.0
Oil Storage Tanks	1.0
Substations	2.0
Main building entrance and gate house entrance	10.0
Roadway	0.5–1.0
Indoor:	

Here two different levels of illumination are recommended:
(a) "general illumination" which determines the average for the entire area, and
(b) "specific illumination" which is designed to facilitate a specific task by providing a higher localized level of illumination.

In power-plant practice, both general and specific indoor brightness are mostly the same. In most instances, a brightness level of 10 foot-candles is recommended. There are, however, exceptions which we shall note briefly.

The three key factors in such an analysis are thus: depreciation on capital investment, power charges, and maintenance. With different lighting systems, these factors tend to offset each other so that annual rate may differ by only a few per cent, although there is a significant difference in the cost of the luminaire. It is essential, therefore that the cost analysis be carried out for different types of lighting installation on an annual basis, and that it be directed specifically to the situation actually encountered (particularly as concerns height of mounting, voltage, and rate of electric power) rather than on any rule-of-thumb.

Special Lighting Requirements

Lighting standards for power plants have been recommended by the Committee on Lighting of Central Station Properties of the Illuminating Engineering Society. These standards are based on an extensive analysis of individual work tasks carried out in generating stations. They form a valuable guide for checking the adequacy of lighting in existing stations and for establishing lighting requirements in new plants. Published during the last two years, the new standards are now being subjected to extensive testing in practice.

Separate analyses are available for outdoor and indoor lighting requirements. Table I shows some of the more important recommended brightness levels.

The highest level of illumination is called for by the instrument repair shop and chemical laboratory. Both of these require both general and specific illumination of 50 ft-candles. An area brightness of 20 ft-candles is called for in the battery rooms, gate house interior, stock rooms, telephone equipment rooms and visitor's gallery (the latter mainly for good public relations).

All other indoor area lighting in power plant stations should have a recommended level of 10 ft-candles. But the following specific tasks require a *localized* illumination of 20 ft-candles: panel boards in auxiliaries and water-treating area, maintenance on machines in boiler feed pump room, boiler gage. Inspection and adjustment of burners (this calls for vertical illumination by luminaires which do not obstruct the outward swing of the burner inspection doors). Localized 20-ft-candle illumination is also required at key points in the hydrogen and carbon dioxide manifold area and for localized lighting of trash rake in screen house.

TABLE II—COMPARISON OF LIGHTING LUMINAIRES

Type	Advantages	Disadvantages
Incandescent	Available in wide variety. Small source. Low initial cost, interchangeable wattage lamps within one luminaire.	Low light efficiency. Short life. High brightness source. Not suited for high vibration and shock conditions.
Mercury	High lighting efficiency. Shock-and-vibration-resistant. Long life.	High lamp brightness. Slow-starting. Requires A.C. Voltage dip may extinguish light.
Fluorescent	High lighting efficiency. Low lamp brightness. Long life. Shock-and-vibration-resistant.	Low light output per lamp. High initial cost. Requires A.C. Difficult and inefficient at low temperatures. Life shortened severely if lamp is started often.

Special requirements are imposed on the luminaries in certain areas. Thus, the light sources in the hydrogen and carbon dioxide manifold area must be of safety-type, vaporproof luminaires must be used near screen house trash rake since these units must be able to withstand water spray during cleaning of the operating equipment. Dust-tight luminaires are recommended in the conveyor areas, in the coal transfer room, the coal crusher feeder and pulverizer areas. Vaporproof lights are called for in the ash sluicing area and are advantageous, but not required in the battery rooms.

In power plant service, three types of luminaire are acceptable: incandescent, mercury, and fluorescent lights. Each of these types has its advantages and disadvantages. The main pros and cons for each type are briefly summarized in Table II.

Within each type of light source, there are different categories according to the distribution which they give to light. The choice of luminaire class depends principally upon ratio of spacing to height. In general, a ratio of 0.5 calls for high concentrating units, a ratio of 0.7 to 1.0 requires a medium spread luninaire, and ratios in excess of 1.0 necessitate widespread light sources. The choice of using high-power widespread units vs. employing a larger number of low-spread luminaires at smaller wattage must be determined by economic evaluation tempered by the physical arrangements.

Regardless of the main lighting methods chosen, safe power plant operation calls for the provision of emergency lighting in key areas in order to permit orderly continued operation or shutdown if the main source of light power breaks down. Such emergency lighting must be provided, above all, in the control rooms, turbine rooms, and exit stairs and passageways. The power supply for these luminaires under emergency conditions should be completely independent of the normal power source, such as a standby generator or storage batteries. The emergency luminaires themselves are normal light units which are merely transferred to the new source of electricity as the occasion demands this. For units in this emergency service, the Illuminating Engineering Society recommends the use of widespread low-wattage luminaires which give maximum area coverage (though at low brightness level) with minimum power.

National Fuels Policy?

In the closing days of the first session of the 86th Congress a Senate-House Concurrent Resolution was introduced to form a Joint Study Committee.

The high point of the resolution was a study committee to recommend an overall fuels policy for peaceful expansion as well as immediate exigencies of national security

American Power Conference Program

THE twenty-second annual meeting of the American Power Conference will be held on March 29, 30 and 31 at the Sherman Hotel in Chicago.

The Conference is sponsored by Illinois Institute of Technology in cooperation with fourteen leading universities and ten national and regional societies throughout the United States.

Tuesday, March 29, 1960. 9:00 a.m. Registration; 10:00 a.m.–12:00 Noon. Opening Meeting

a. Invocation. (To be announced.)
b. The Morality of the Profit System. John Conrad, President, S & C Electric Company, Chicago, Ill.

12:15 p.m. Joint APC-ASME Luncheon. Sponsored by American Society of Mechanical Engineers

Chairman: S. P. Kezios, Chairman, Chicago Section ASME.
Co-Chairman: Andrew A. Fejer, Chairman, Department of Mechanical Engineering, Illinois Institute of Technology, Chicago, Ill.
Speaker: Walker Cisler, President, American Society of Mechanical Engineers.
Subject: An American Engineer in Russia.

2:00–5:00 p.m. Steam Generators

a. Predicting Tube Life in High Temperature Boiler Installations. J. L. Menson, Director of Operations, Combustion Engineering Company, New York, N. Y.
b. Nuclear Heated Boilers. Robert C. Barnett, Nuclear Component Specialist and Norval McDonald, Manager, Proposition Section. The Babcock & Wilcox Company, Barberton, Ohio.
c. Some Aspects in the Control and Interlocking of a Gas-Fired Boiler-Turbine-Generator Unit. Edward H. Finch and L. Skog, Jr., Associates, Sargent & Lundy Engineers, Chicago, Ill.
d. Some Applications of the Low Level Economizer. James H. Potter, Dean of Graduate Studies, Stevens Institute of Technology, Hoboken, N. J.

2:00–5:00 p.m. Turbine Generators

Chairman: W. A. Lewis, Professor of Electrical Engineering, Illinois Institute of Technology, Chicago, Ill.
Co-Chairman: F. M. Scott, Supervisor, Utility Sales, Allis-Chalmers Manufacturing Company, Chicago, Ill.

a. Operating Experience with Conductor-Cooled Turbine-Generators. L. M. Abrahamson, Manager of Power Production, Wisconsin Power and Light Company, Madison, Wis., and L. T. Rosenberg, Chief Generator Design Engineer, Allis-Chalmers Manufacturing Company, Milwaukee, Wisc.
b. Four Years' Operating Experience with Large Liquid Cooled Turbine-Generators. C. E. Kilbourne, Manager, Product Planning, and C. H. Holley, Manager, Generator Department, General Electric Company, Schenectady, N. Y.
c. Operating Experience with Inner Cooled Turbine-Generators. Owen K. Brown, Chief Electrical Engineer, Niagara Mohawk Power Corporation, Buffalo, N. Y., and J. W. Batchelor, Manager, Turbine Generator Engineering Department, Westinghouse Electric Corporation, East Pittsburgh, Pa.

2:00–3:30 p.m. Water Technology I—Advances in Evaporation Techniques

(Program to be announced.)

2:00–3:00 p.m. Space Heating

Chairman: Donald H. Madsen, Associate Professor of Mechanical Engineering, State University of Iowa, Iowa City, Iowa.
Co-Chairman: Lois Graham, Assistant Professor of Mechanical Engineering, Illinois Institute of Technology, Chicago, Ill.

a. Solar Energy for Future Heat Pumps. E. B. Penrod, Professor and Head of the Department of Mechanical Engineering, University of Kentucky, Lexington, Ky., and K. V. Prasanna, Department of Mechanical Engineering, Illinois Institute of Technology, Chicago, Ill.
b. Methods for Evaluating Heat Losses in Concrete Slabs. M. A. Chaszeyka, Research Engineer, Armour Research Foundation and S. P. Kezios, Professor of Mechanical Engineering, Illinois Institute of Technology, Chicago, Ill.

3:30–5:00 p.m. Fuel Cell Tractor and Electric Auto

Chairman: D. J. Renwick, Associate Professor of Mechanical Engineering, Michigan State University, East Lansing, Mich.
Co-Chairman:

a. The Fuel Cell Tractor. W. Mitchell, Jr., Associate Director of Research, Allis-Chalmers Manufacturing Company, Milwaukee, Wis.
b. The Electric Auto. Claud R. Erickson, Mechanical Engineer, Board of Water and Light, Lansing, Mich.

3:30–5:00 p.m. Industrial Plants I—Industrial Power Plant Safety

Chairman: Kenneth R. Hodges, Chief Engineer, Sears Roebuck & Company, Chicago, Ill.
Co-Chairman:

a. Flame Failure Protection for Industrial Boilers. H. Christiansen, Midwest Regional Sales Manager, Combustion Control Division, Electronics Corporation of America, Chicago, Ill.
b. Power Plant Safety. Wilbur C. Kramer, Assistant Station Superintendent, State Line Station, Commonwealth Edison Company of Indiana, Hammond, Ind.

8:00–10:00 p.m. Evening General Interest Session—Advanced Engineering Concepts

a. Magnetohydrodynamic Power. A. Kantrowitz, Avco-Everett Research Laboratory, Everett, Mass.
b. Isotopic Heat and Power. W. W. T. Crane, The Martin Company, Baltimore, Md.
c. Nuclear Rocket Program—Where it is and Where it is Going. H. R. Schmidt, Lt. Col., Aircraft Reactors Branch, Division of Reactor Development, Washington, D. C.
d. Fuel Cells. Everett Gorin, Pittsburgh Consolidation Coal Company, Pittsburgh, Pa.

Wednesday, March 30, 1960. 9:00 a.m.–12:00 Noon. Power Generation for Peak Loads

a. New Generation Concepts and How They May be Applied. W. D. Marsh and A. G. Mellor, General Electric Company, Schenectady.
b. How Shall We Meet Peaking Requirements? L. B. LeVesconte and Tor Kolflat, Sargent & Lundy, Engineers, Chicago, Ill.
c. Economics of Peaking. F. A. Ritchings, Ebasco Services Incorporated, New York, N. Y.
d. The Economics of a Twenty-Two Thousand Kilowatt Peaking Gas Turbine. J. O. Stephens, Engineering Manager, Industrial Gas Turbine Department, Philadelphia Pa., and B. L. Lloyd, Manager Project Section, Electric Utility Engineering Department, Westinghouse Electric Corporation, East Pittsburgh.

9:00–10:30 a.m. Communications Protection and Control

Chairman: A. A. Casey, Vice President, Cleveland Electric Illuminating Company, Cleveland, Ohio.
Co-Chairman: J. W. Nilsson, Associate Professor of Electrical Engineering, Iowa State University, Ames, Iowa.

(Continued on page 64)

a. Modern Techniques and Methods for Power Line Carrier and Telemetering. Otto Kries, Brown Boveri, Ltd., Montreal, Quebec, Canada.

b. Remote Control with Data Logging. W. F. Cruess, Engineering Manager, Supervisory Control Section, Power Control and Communication Department, Westinghouse Electric Corporation, East Pittsburgh, Pa.

c. Operating Experience with a Microwave System Used with Protective Relaying. J. Leo Harmon, Supervisor, Control Testing Unit, Cleveland Electric Illuminating Company, Cleveland, Ohio.

9:00–10:30 a.m. Water Technology II—Analytical Control and Methods

(Program to be announced.)

10:30 a.m.–12:00 Noon. Water Technology III—Ion Exchange

(Program to be announced.)

12:15 p.m. APC-AIEE Luncheon. Sponsored by the American Institute of Electrical Engineers

Chairman: J. H. Foote, President, American Society of Electrical Engineers.

Co-Chairman: Francis Cox, Chairman, Chicago Section AIEE.

Speaker: (To be announced.)

2:00–5:00 p.m. Large Steam Turbines

a. Economics of Very Large Turbine Generators. J. R. Carlson, Engineering Manager, Steam Division, Westinghouse Electric Corporation, Philadelphia, Pa.

b. Large Steam Turbine-Generators with Spinning Reserve Capacity. J. E. Downs, Manager, Turbine Engineering, and E. H. Miller, Manager, Turbine Advance Engineering, General Electric Company, Schenectady, N. Y.

c. Factors Influencing the Reliability of Large Steam Turbine Generator Units. Charles D. Wilson, Chief Turbine Design Engineer, Allis-Chalmers Manufacturing Company, Milwaukee, Wis.

2:00–5:00 p.m. Water Technology IV—Water Conservation in Industry

2:00–5:00 p.m. Fuels Sponsored by the Fuels Division, ASME.

a. Slag Tap Boiler Performance Associated with Power Plant Flyash Disposal. H. M. Rayner, Mechanical Engineer, Western Electric Company, Inc., Chicago, Ill., and L. P. Copian, Design Engineer, Riley Stoker Corporation, Worcester, Mass.

b. Measurement of Density and Moisture in Large Coal Storage Piles. A. S. Grimes Section Head, Results Engineering, American Electric Power Service Corp., New York.

c. The Factory Fabricated Coal Fired Boiler. LeRoy F. Deming, Manager, Power Generation Branch, United States Navy, Bureau of Yards and Docks, Washington.

6:30 p.m. All Engineers Dinner

Thursday, March 31, 1960. 9:00 a.m.–12:00 Noon. Nuclear Power I

a. Progress Report on the Dresden Nuclear Power Plant. V. D. Nixson, General Electric Company, and J. J. Poer, Commonwealth Edison Company, Chicago, Ill.

b. Economic Nuclear Power—When? W. L. Budge, Westinghouse Electric Company, Pittsburgh, Pa.

c. Superheated Steam from Nuclear Energy, C. R. Braun and C. B. Graham. Allis-Chalmers Mfg. Co.

9:00 a.m.–12:00 Noon. Central Station Plants and Auxiliaries

a. Problems in the Design of Concrete Chimneys. David O. Thompson, Building Design Engineer, Commonwealth Edison Company, and Max Zar, Associate and Structural Engineer, Sargent & Lundy, Engineers, Chicago, Ill.

b. Selection of Boiler Feed Pump Drive for 250 Mw Turbine-Generator Unit. John C. Beres, Mechanical Technical Engineer, and Robert W. Potts. Engineer, Commonwealth Associates, Inc., Jackson, Mich.

c. Mechanical Draft Fans in the Future—Critical Areas in Application. William E. Wendover, Senior Power Application Engineer, American Standard Industrial Division, Detroit, Mich.

d. Structural Stability of Commercial Wrought Austenitic Steel for 1150 to 1450 F Power Plant Piping. E. A. Sticha, Chief Research Metallurgist, Edward Valves, Inc., East Chicago, Ind.

9:00 a.m.–12:00 Noon. Industrial Plants II

a. A Generalized Computer Program for Evaluating Industrial Turbine Performance. A. J. Klomparens and R. W. Hermanson, Dow Chemical Company, Midland, Mich.

b. Novel Features of a New Central Power Plant to Replace Four Separate Plants. Harold H. Reisman, Manager, Power Plant Division, Deere & Company, Moline, Ill.

c. Pond Surface Cooling for Chemical Plant Cooling Water. Bruce Bardin and Alex Regan, Union Carbide Chemicals Company, Seadrift, Tex.

9:00 a.m.–12:00 Noon. System Planning and Operation

Chairman: Nathan Cohn, Vice President, Technical Affairs, Leeds and Northrup Company, Philadelphia, Pa.

Co-Chairman: M. Riaz, Professor of Electrical Engineering, University of Minnesota, Minneapolis, Minn.

a. New Tools Improve System Generation Planning. C. D. Galloway and L. K. Kirchmayer, Operational Investigations Manager, General Electric Co., Schenectady, N. Y.

b. Operational Gaming and the Use of Mathematical Models for Developing System Economics and Planning. C. J. Baldwin, Project Engineer, Westinghouse Electric Corporation, East Pittsburgh, Pa., and C. H. Hoffman, Senior Engineer, Public Service Electric and Gas Company, Newark, N. J.

c. Closing the Computer Loop on System Regulation. W. J. Brogden, Carolina Power and Light Company, Raleigh, N. C.

d. Progress in Automation of Electric Power System Planning and Operation. C. Concordia, Manager, General Analytical Engineering, and F. J. Maginniss, Manager, Special Studies and Digital Analysis Engineering, General Electric Company, Schenectady, N. Y.

10:30 a.m.–12:00 Noon. Industrial Plants II

Chairman: Hugh H. Foreman, President, National Association of Power Engineers.

Co-Chairman:

Ash Handling Systems for Power Plants. Arthur M. Perrin, President, National Conveyors Company, Inc., Bergen County, N. J.

b. Combustion of Residual Fuel Oils. David S. Frank, Assistant Refinery Technical Manager, Pure Oil Company, Chicago, Ill.

c. Factors to Consider in the Application of Centrifugal Pumps. R. E. Allen, Ingersoll-Rand Company, New York, N. Y.

12:15 p.m. Joint APC-WSE Luncheon Sponsored by Western Society of Engineers

Chairman: J. T. Rettaliata, President, Western Society of Engineers and President, Illinois Institute of Technology, Chicago, Ill.

Co-Chairman:

Speaker: Allen S. King, President, Northern States Power Company, Minneapolis, Minn.

Subject: The Challenge of the Power Industry.

2:00–5:00 p.m. Nuclear Power II

a. Gas-Graphite Suspension-Cooled Reactor. G. K. Rhode, D. C. Schluderberg, E. E. Walsh and D. M. Roberts, Babcock and Wilcox Company, Lynchburg, Va.

Abstracts From the Technical Press—Abroad and Domestic

(Drawn from the Monthly Technical Bulletin, International Combustion, Ltd., London, W. C. 1)

Fuels: Sources, Properties and Preparation

The Oxidation of Bituminous Coal by Air. Formation, Composition, and Properties of Oxidized Coals and Humic Acids. O. Grosskinsky, G. Huck and W. Lange. *Brennst Chemie* 1959, **40** (Aug.), 252–61 (In German).

Experimental studies are presented of the way in which oxygen is built into the molecular structure of the coal, its components and the humic acids during oxidation. The results of the studies are discussed mainly with regard to the chemical structure of coal and humic acids.

The Chemistry of Carbonization Investigated on Polymeric Model Substances of Bituminous Coal. IV. Pyrolysis of Model Substances without Special Functional Groups. P. M. J. Wolfs, H. I. Waterman and D. W. van Krevelen. *Brennst Chemie* 1959, **40** (Aug.), 241–51 (in German).

The use of radioactive formaldehyde made possible a determination of the number of bridges in the original materials and also to follow the mechanism of pyrolysis by a combination of radiochemical, thermogravimetric and analytical methods. Two phases could be distinguished, a primary one of depolymerization. The aromatic hydrogen is liberated during the secondary phase in which no tar formation occurs. This hydrogen forms methane the carbon being taken from the whole carbon skeleton.

Mechanical Handling

Flow of Bulk Granular Materials. H. J. Barre. *A.S.M.E. Preprint* No. 59-SA-46 1959, (June), 4 pp.

A brief review of what is known about the flow of materials from hoppers and the factors affecting it is followed by a discussion of means of improving the flow under various circumstances.

Cycles and Transmission

Heat Transfer in the Critical Pressure Range with Forced Flow of the Working Medium. M. A. Styrikovitch, S. L. Mikropolsky and M. E. Shitzman. *Mitt. V.G.B.* No. 61, 1959 (Aug.), 288–94.

Theoretical and experimental work on heat transfer at high pressures and temperatures is described and the good agreement of results emphasized. Nomograms are presented for the determination of local heat transfer coefficients.

Steam Generation and Power Production

The Experimental Investigation into the Heat Capacity of Water at Temperatures from 10 to 500 C and Pressures up to 500 kg/cm². A. M. Syrota and B. K. Malzev. *Teploenergetika* 1959 (Sept.), 7–15 (in Russian).

The results obtained are presented in tables and graphs and compared with those of other authors.

Precision Analysis and the Combined Table of Experimental Values of the Specific Volume of Water and Water Vapor Obtained in the Moscow Power Institute. V. A. Kirilin and S. A. Ouilibin. *Terploenergetika* 1959 (Sept.), 3–7 (in Russian).

The accuracy of the results obtained for specific volume of water and water vapor at temperatures up to 650 C and pressures up to 900 kg/cm² has been analyzed and two tables are presented, one giving reliable and the other giving unreliable data.

The Viscosity of Water Vapor at Atmospheric Pressure. A. S. Shifrin. *Teploenergetika* 1959 (Sept.), 22–7 (in Russian).

The viscosity of water vapor at atmospheric pressure and temperatures up to 866 C has been measured by the two capillaries method. The results are presented in tables and graphs.

Unstable Thermal Stresses in Cylindrical Hollow Cylinders. J. Böhm and R. Ehrich. *Mitt. V.G.B.* No. 61, 1959 (Aug.), 307–14 (in German).

The equations are derived for sudden and linearly occurring changes of temperature of the steam flowing through a pipe. The application of the equations is illustrated by examples.

Investigations into Pressure Drop due to Friction of Water-Steam Mixtures and the Slip Velocity of the Steam in

(*Continued on page 66*)

Vertical Boiler Tubes. K. Jaroschek and F. Brandt. *B.W.K.* 1959, **11** (Sept.), 407–13 (in German).

Laboratory tests on a full-scale plant with an inner tube dia. of 57.5 mm (2.25 in.) were made at pressures up to 200 atü (2900 psi) to determine the slip velocity of the steam and the friction coefficient. Increased turbulence of the water-steam mixture is thought to be responsible for the higher friction coefficients found. It is believed that the diameter of the tube has also an influence on the friction coefficient but its verification must await further tests. A theory for the slip velocity of the steam is put forward.

Thermal Design of a Steam Generating Unit with the Assistance of the "Ural" Computer. M. P. Simoyu, F. A. Voulman and S. A. Stavtzeva. *Teploenergetika* 1959 (Sept.), 32–9 (in Russian).

The method developed for using a computer in steam generator design is described.

Packaged Fire-tube Boilers. G. Whittingham. *J. Inst. Fuel* 1959, **32** (Aug.), 370–4.

The important design features of liquid fuel fired shell-type boilers are described and combustion control, feedwater treatment and performance discussed briefly.

Application of Cyclone-Furnace Firing to Industrial Boilers. C. T. Smith. *A.S.M.E. Preprint* No. 59-SA-53 1959 (June), 20 pp.

The advantages of the horizontal cyclone furance over pulverized coal firing are outlined and examples of installations described. The fuel used is coal, lignite, bark, gas and oil either singly or in combination. Boiler sizes range from 125 klb/h to 500 klb/h.

The Economic Purchasing of Coal for Small Boiler Plants. G. Armstrong. *Steam Engr.* 1959, **28** (Aug.), 327–9.

The coal evaluation system worked out by I.C.I. is explained and illustrated by examples. The level of coal stock to be held is also discussed.

Dimensionless Coefficients of Mixture Formation in Combustion Chambers. Part IV. W. H. Fritsch. *Energie* 1959, **11** (Aug.), 340–3 (in German).

The determination of the mixture coefficient from results of maximum load tests on the combustion chamber described in Pt. III (abstract 4811) is described and from this the relationship between Fourier number and excess air established. It is concluded that the field of concentration in this combustion chamber was much more uniform than in the usual ones,

much higher heat release rates were obtained together with extremely short mixing times and the mixing coefficient was a function of excess air and chamber pressure increasing with increasing values of both.

Water-Side Corrosion and Water Treatment

The Conditions of Weak Mineral Salts Transition from Boiler Feed Water into Saturated Steam and the Effect of Feed Water Alkalinity (pH) on this Process. M. A. Strykovitch, O. I. Martinova, I. H. Haybullin and E. I. Mingoulina. *Teploenergetika* 1959 (Sept.), 50–6 (in Russian).

Screening Tests of Inhibitors to Prevent Chloride Stress Corrosion. J. H. Phillips and W. J. Singley. *Corrosion* 1959, **15** (Sept.), 18–22.

The effect of various inhibitors on the stress corrosion attack of austentic stainless steel by chloride contained in alkaline-phosphate boiler water have been studied in the laboratory. A combination of sodium nitrate and sodium sulfite seemed to be the best inhibitor but in subsequent tests on shell- and tube model boilers with sodium nitrate cracking was found. Further tests are in progress to resolve this discrepancy.

Four-Tower Water Treatment Test Facility. R. G. Murray and M. E. Tester. *Corrosion* 1959, **17** (Sept.), 60–4.

The apparatus used to study corrosion of copper condenser tubes and the tests made at two levels of water velocity and two water temperatures are described. Pitting corrosion was found in tubes with water at low velocity and this was more severe in the high than low water temperature test. No correlation was found between the amount of silt deposited and the severity of pitting.

Significance of Copper Deposits Associated with a Boiler Tube Failure. J. C. Spurr. *Corrosion Techn.* 1959, **6** (Aug.), 233–7.

It was noticed that the tube failures were associated with considerable deposits of copper around the bursts. Detailed examinations and laboratory tests suggest that the method of formation of metallic copper deposits in the tubes was by overheating of tubes containing a layer of copper hydroxide or copper oxide sludge and intergranular copper penetrations due to the action of molten copper. The temperatures in this latter case must have been at least 1900 F. A further requirement was the occurrence of stresses due to thermal shock.

Gas-Side Corrosion and Deposits

A Review of Available Information on Corrosion and Deposits in Coal- and Oil-Fired Boilers and Gas Turbines. Report of ASME Research Committee on Corrosion and Deposits from Combustion Gases. Battelle Memorial Institute, H. W. Nelson, H. H. Krause, E. W. Ungar, A. A. Putnam, C. J. Slunder, P. D. Miller, J. D. Hummel and B. A. Landry. *Pergamon Press*, London, 1959, 198 pp.

The contents of this detailed review are: 1. Introduction (gaps in our knowledge on external deposits and corrosion in boilers and gas turbines); 2. Mineral constituents in coal and their behavior during combustion; 3. Ash-forming constituents in heavy fuel oil and their behavior during combustion; 4. Oxides of sulfur in boilers and gas turbines; 5. The physical aspects of deposition in boiler and gas turbine systems; 7. High-temperature corrosion; 8. Corrosion of metals exposed to combustion gases below 400 F; 9. The removal of solids from combustion gases. Each chapter has its own summary and list of references.

Flue Gas Side Corrosions. Pt. III. SO_2, SO_3, Dew Point and Measuring Techniques. Pt. IV. Summaries and Material Problems. W. Gumz. *B.W.K.* 1959, **11** (Sept.), 425–9 (in German).

A review of the literature of recent years in the two fields. An appendix reviews some of the latest (1959) contributions, especially those relating to oil firing.

Fire Side Corrosion in Oil-Fired Boilers. L. K. Rendle, R. D. Wilson, and G. Whittingham. *Combustion* 1959, **31** (Aug.), 30–41.

Laboratory, pilot-scale and full-scale plant investigations are reported, divided into high-temperature and low-temperature studies. In the former, various steels differing in Cr content (cooled) and heat resisting alloys (uncooled) were exposed to combustion gases from fuel oil with low and high V content, without and with addition of dolomite. It is concluded that the corrosion resistance of superheater tubes at 900–1300 F increases with increasing Cr content and that uncooled stainless steels at 1500 F are more resistant to combustion gases from low V and high S content oil than nickel base alloys. The addition of dolomite led to rapid blockage of the tube banks. In the low temperature corrosion tests the beneficial effect of ammonia injection was confirmed.

Suppression of the Sulfuric Acid Dew

Point by Teramin. K. Wickert. *Energie* 1959, **11** (Apr.), 344–50 (in German).

The reasons for the corrosion inhibiting properties of Teramin have been studied in the laboratory and the tests carried out at temperatures of 20, 60, 100 F and higher and their results are described. Teramin reacts with H_2SO_4 to form Teramin sulfates which have the same inhibiting effects as Teramin itself. The sulfates are water soluble and the heating surfaces can thus be easily cleaned by water washing. They are also nonflammable and incombustible.

Flue Gas, Ash and Dust

Building Materials Produced from Combustion Residues of Slagging and Granulating Boilers. H. Erythropel. *Mitt. V.G.B.* No. 61, 1959 (Aug.), 257–61 (in German).

German experience in the utilization of fly ash and granulated slag for building materials is presented, costs of plants given and the competitiveness of the new with conventional products discussed.

Survey of Present and Future Developments in the Utilization of Fly Ash in Great Britian. H. W. G. Dedman. *Mitt. V.G.B.* No. 61, 1959 (Aug.), 261–5 (in German).

Limit values of the various constituents of fly ash for different uses are tabulated and the main fields of utilization described: 1. Standard light concrete building bricks; 2. Building bricks; 3. Light aggregates; 4. Partial replacement of cement or as addition to cement or sand in concrete; 5. Road and dam building; 6. Filling-up of building land.

Some Practical Examples of the Utilization of Fly Ash for Dams, Road Foundations and Bituminous Surfaces. J. Glover. *Mitt. V.G.B.* No. 61, 1959, (Aug.), 266–73 (in German).

Various applications in Great Britain are described and the results obtained are discussed.

Stack Emission Control during Power-Plant Load Cycling. J. F. McLaughlin and G. V. Williamson. *A.S.M.E. Preprint* No. 59-SA-28, 1959 (June), 4 pp.

Avoidance of smoke nuisance from older boiler plants, especially during rapid load changes, is discussed. Replacement and modernization of older boilers, changes in fuel used, improved instrumentation, changes in operating procedures and application of schedules avoiding sudden load swings are recommended measures; examples of their application are cited.

The Concentration of Sulfur Dioxide in the Atmosphere Near Power Stations. W. G. Cummings and M. W. Redfearn. *J. Inst. Fuel* 1959, **32** (Aug.), 358–63.

The results of measurements with a portable SO_2 meter in the neighbourhood of 11 power stations with chimneys from 150–450 ft. height are tabulated. It is shown that the concentration of SO_2 at ground level at all stations was low.

Power Generation and Power Plant

Thermoelectric Power. An Investigation of its Possibilities. Part 1. Present Methods of Power Generation. Part 2. Engineering Design Parameters and Performance. Part 3. General Discussion and Approximate Analysis of Economics. G. W. Wilson and B. C. Lindley. *Engineering* 1959, **188** (Aug. 28), 97–9; (Sept. 4), 129–32; (Sept. 11), 161–2.

The first part deals with thermoelectric devices, efficiency of thermoelectric generation, thermionic diode converter and the gas-filled diode; the second with materials, thermoelements, thermopiles, heat sources and sinks, configurations of thermoelectric generator and its use with organic-moderated reactor; the third with a general discussion of the various types, and applications.

Efficiency of Steam Generation III. J. N. Williams. *Pwr and Wrks Engng.* 1959, **54** (Aug.), 463–9.

This third part deals with methods of direct measurement of efficiency and the instruments required for this purpose, viz. fuel sampling and analysis, coal weighing, feedwater and steam flow metering, pressure and temperature meters.

Design Features of New Coal-Burning Plants. Anon. *Coal Utilization* 1959, **13** (Aug.), 22–7.

Some examples of typical installations from the largest steam generators to the smallest hot water boilers are described. Most of these have both automatic coal feed and ash removal systems.

Aasnaes Power Station (Denmark). Anon. *Elektroteknikeren* 1959, **55** (June 8), 160–7 (in Danish).

An account is given of all features of this station which is equipped with two 120 MW sets each unit-connected with a 400 tons/hr. dual-fuel boiler. Steam temperature is 540 C at T.S.V., pressure 130 kg/cm². From cold, the best start-up time is 55 minutes to paralleling and 115 minutes to 100 MW; after 6 hours shut-down, 30 and 50 minutes respectively.

From *C.E.G.B. Digest* 1959, **11** (Aug. 15), 2022.

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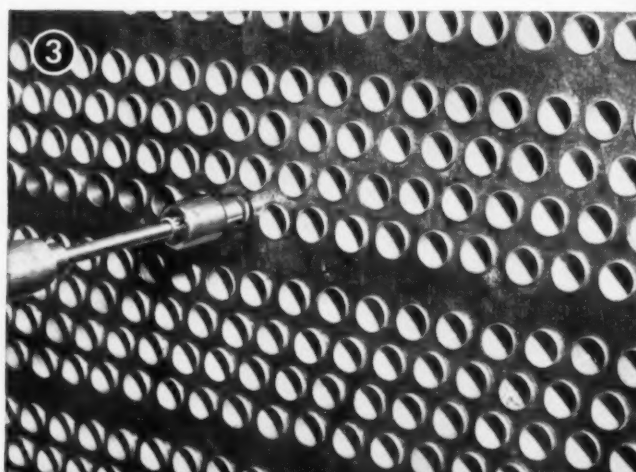

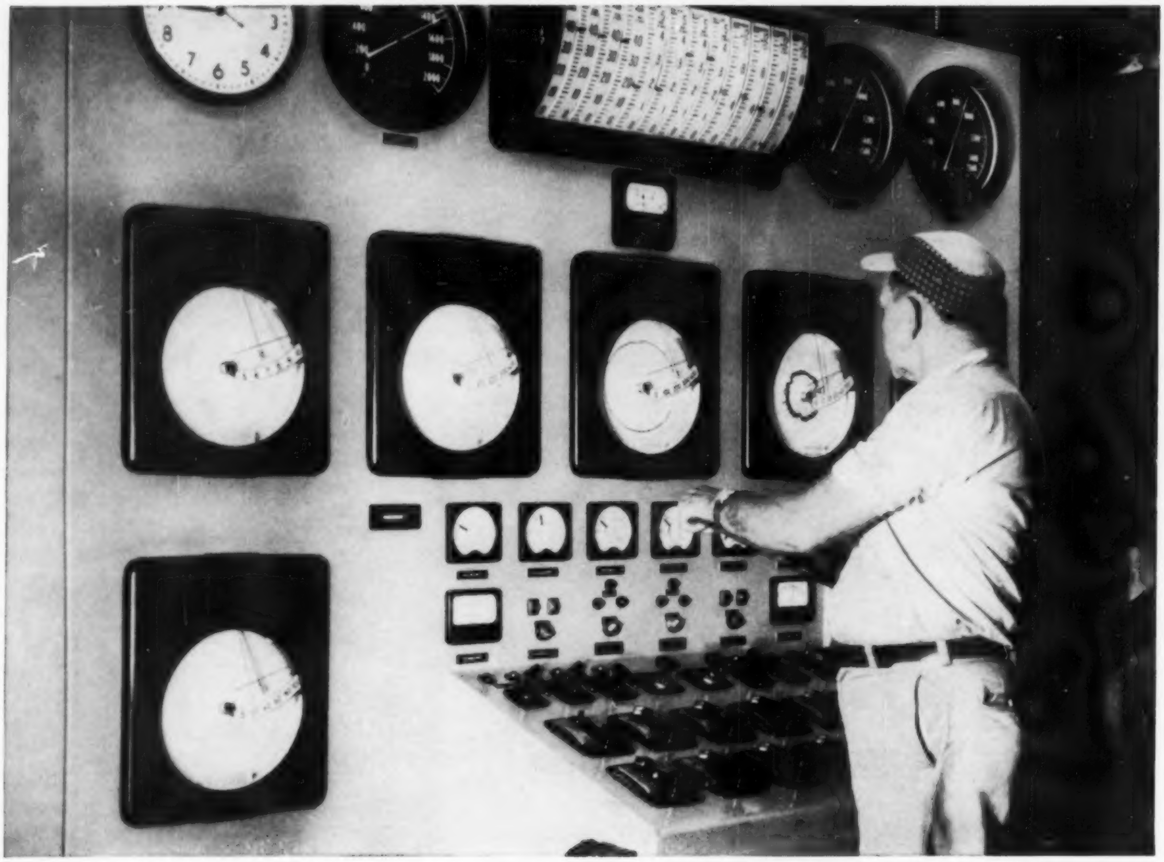

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Advertisers' Index

Aero Research Instrument Co., Inc. 61
Aerotec Industries, Inc. .... *
Air Preheater Corporation, The 5
American Brass Company..... *
American-Standard Industrial Division...................41-44

Bailey Meter Company........ 72
Baltimore & Ohio Railroad.... 66
Bayer Company, The.......... 73
Bird-Archer Company........ *
Bituminous Coal Institute..2 and 3
Buell Engineering Company, Inc. 24
Buffalo Forge Company........ *

Cambridge Instrument Company....................... 61
Clarage Fan Company........ *
Combustion Engineering, Inc. ....Second Cover, 22 and 23
Copper-Bessemer............. *
Copes-Vulcan Div., Blaw-Knox Company...............10 and 11
Crane Co...................... *

Dampney Company, The.7 and 68
Dearborn Chemical Company. 21
De Laval Steam Turbine Company....................... *
Diamond Power Specialty Corporation........Third Cover
Dow Industrial Service, Div. of The Dow Chemical Company ....Fourth Cover
Dravo Corporation............ 6
E. I. du Pont de Nemours & Co., Grasselli Chemicals Dept....................... *

Eastern Gas & Fuel Associates *
Edward Valves, Inc........... *
Engineer Co., The............ *

Fairmount Chemical Co....... 65
Fly Ash Arrestor Corp......... 75

Green Fuel Economizer Company, Inc., The............. 17

Hagan Chemicals & Controls, Inc.......................... 19

Illinois Water Treatment Co... 67
Ingersoll-Rand Company...... 4

Johns-Manville............... *

(Continued on page 75)

M. W. Kellogg Company, The. 16
Koppers Company, The....... *

Leeds & Northrup Company.. 8

Manning, Maxwell & Moore, Inc....................... *
Maryland Shipbuilding & Drydock Company.............. *
W. K. Mitchell & Company.... 18
Morton Salt Company......... *

Nalco Chemical Company..... 63

Peabody Engineering Corporation...................... *
Pennsylvania Crusher Div., Bath Iron Works Corp....... 9
Pfaudler Permutit, Inc....... *
Chas. Pfizer & Co., Inc........ 59
Pittsburgh Piping & Equipment Company............. 12
Powell Valves................. *

Refractory & Insulation Corporation....................... 69
Reliance Gauge Column Company, The.................. *
Republic Flow Meters Company....................... 15
Republic Steel Corporation.... ....70 and 71
Research-Cottrell, Inc......... 20
Richardson Scale Company... 74
Rohm & Haas Company....... 76

Standard Tube Co., The and Michigan Steel Tube Products Div.................... *
Stock Equipment Company... *
Sumco Engineering, Inc....... *
Sy-Co Corporation........... *

Todd Shipyards Corp., Products Div.................... *

Unafax Construction Co....... *
United Electrical Coal Companies, The................. *

Valley Camp Coal Co.......... 14

Warren Pumps, Inc........... *
Western Precipitation Corporation...................... *
Westinghouse Electric Corp., Sturtevant Div............. *
Worthington Corporation..... *

Yarnall-Waring Company..... 13
Yuba Consolidated Industries Inc....................... 54

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